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COLUMBIA-NORTH PACIFIC REGION COMPREHENSIVE FRAMEWORK STUDY OF --ETC(U)
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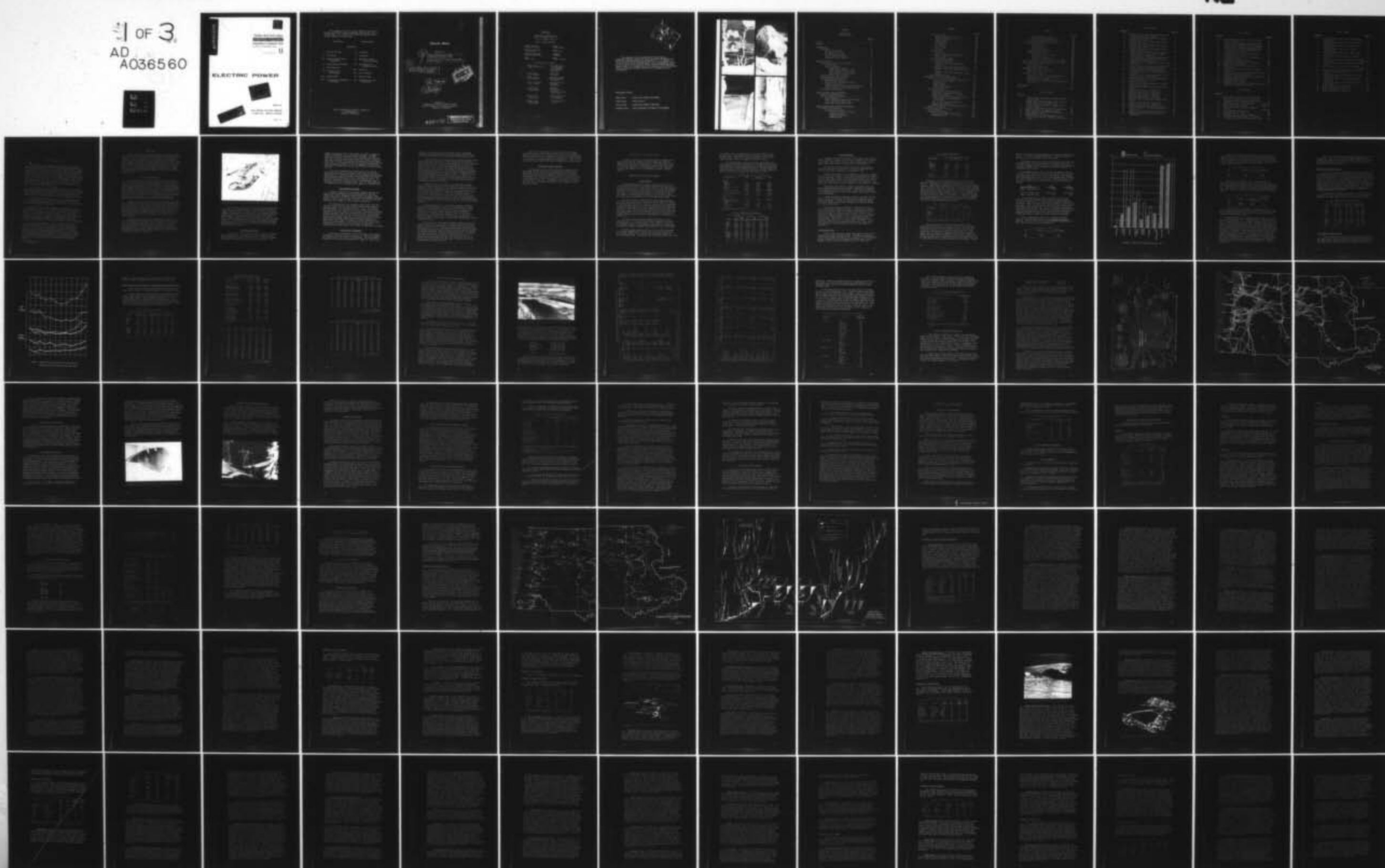

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(1)

Columbia-North Pacific Region

Comprehensive Framework Study
of Water and Related Lands

APPENDIX XV

ELECTRIC POWER

SUBMITTED BY

PACIFIC NORTHWEST RIVER BASINS COMMISSION
1 COLUMBIA RIVER, VANCOUVER, WASHINGTON

OCTOBER 1970

This appendix is one of a series making up the complete Columbia-North Pacific Region Framework Study on water and related lands. The results of the study are contained in the several documents as shown below:

Main Report

Summary Report

Appendices

I. History of Study

II. The Region

III. Legal & Administrative Background

IV. Land & Mineral Resources

V. Water Resources

VI. Economic Base & Projections

VII. Flood Control

VIII. Land Measures & Watershed Protection

IX. Irrigation

X. Navigation

XI. Municipal & Industrial Water Supply

XII. Water Quality & Pollution Control

XIII. Recreation

XIV. Fish & Wildlife

XV. Electric Power

XVI. Comprehensive Framework Plans

Pacific Northwest River Basins Commission
1 Columbia River
Vancouver, Washington

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Electric Power

APPENDIX XV

(9) Columbia-North Pacific Region
Comprehensive Framework Study
of Water and Related Lands. Appendix XV.
Electric Power,

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(11) October 1970

(12) 212p.

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APPENDIX XV
Electric Power

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This appendix to the Columbia-North Pacific Region Framework Report was prepared at field level under the auspices of the Pacific Northwest River Basins Commission. It is subject to review by the interested Federal agencies at the departmental level, by the Governors of the affected States, and by the Water Resources Council prior to its transmittal to the President of the United States for his review and ultimate transmittal to the Congress for its consideration.

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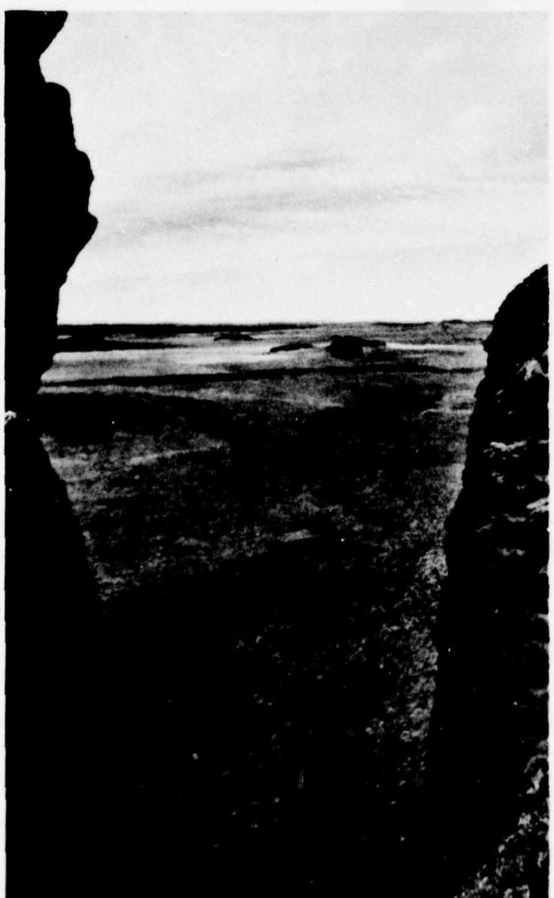


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INTRODUCTION

The purpose in this appendix is to forecast power loads, generation, and transmission for the Columbia-North Pacific Region as they relate to the future use of water. These measures of power development are related to other water and land uses through their modification of water supplies of the region. The impact on water supplies is twofold. First, the development of hydroelectric capability has a major influence on use of water supplies for other purposes. In many instances it is a major determinant for water control, where the conflict with other water uses is slight. Second, the development of thermal electric capability will require a water supply for steam condensation which must be considered with use of water supplies for other purposes.

The appendix has been formulated specifically in keeping with standards of the Water Resources Council (49).1/ As such, it relates power development to the broad-scaled analysis of water and related land resource problems and furnishes a general appraisal of the probable nature, extent, and timing of power development in the region.

Although project formulation studies were not undertaken, specific generating projects at each of the three levels of power development have been identified for study purposes. These levels were the years 1980, 2000, and 2020.

For some portions of the appendix, studies were made in considerable detail. This is particularly true of the studies which developed the staging of electric power development. Such detail, however, is not in conflict with the objective of broad-scaled analysis. The detail is in study of a power system not in the study of individual projects. Studies of such detail have been made possible only through the mathematical simulation of the entire regional power generating system on large capacity digital computers.

In most other appendixes of this framework study, the Columbia-North Pacific Region has been divided into subregions. This was not done for the power appendix as the results thereof would be of little value. Although it is entirely feasible to identify power loads and generation by subregions, a coordinated power system serves the Pacific Northwest in its entirety by means of a high-voltage transmission network. Some subregions are relatively power rich and their resources are used to help meet the needs of other subregions which have high loads but few power resources.

1/ See Bibliography.

BACKGROUND

Electric power service to the region may have begun in 1882, when the first electric light plant in Washington began operation in Tacoma. On June 3, 1889, a hydroelectric plant was completed at Willamette Falls at Oregon City. In September 1890, alternators were installed at the plant and were connected with Portland by what may be regarded as the first long-distance transmission line in the United States. This plant, considerably modified, operates today as the T. W. Sullivan plant of Portland General Electric Company. Municipal electric plants began operation in McMinnville in 1889, in Centralia in 1893, in Tacoma in 1894, in Seattle in 1902, and in Eugene in 1910.

The Private Utilities

The privately owned utilities which serve the region had their origin in small, locally owned enterprises to provide utility services including gas supply and electricity. Some were subsidiaries of railroad companies. Puget Sound Power & Light Company was formed through an extensive series of mergers in western Washington which established the company in 1912, and continued through 1940. The Washington Water Power Company started as a small enterprise in Spokane in 1885. Through successive reorganizations it evolved into a successful electric and street railway company by 1899, although acquisition of other small systems in western Washington and northern Idaho continued for a considerable period thereafter.

Through a similar pattern of successive reorganization other major privately owned utilities sprang up in Oregon and Washington. The Pacific Power & Light Company was incorporated in June 16, 1910. This company, which originally served southeastern Washington and northeastern Oregon, subsequently merged on separate occasions with Northwestern Electric Company, Mountain States Power Company, and California Oregon Power Company to become the largest privately owned utility in the region. In addition, the company serves central Wyoming.

The Portland General Electric Company serves part of the city of Portland and adjoining areas in northwestern Oregon. From its small beginning at Willamette Falls in 1889, it went through successive reorganizations to become the company it is today. Active opposition to the company at an early date resulted in a referendum in 1912, by which Portland extended a franchise also to Northwestern Electric Company, thus creating an unusual condition of competition within a single city.

Public utility generation in the Pacific Northwest had its beginning at Willamette Falls (Crown Zellerbach Corp.).

For a long period the private utilities in the region were subsidiaries of holding companies. Both Washington Water Power Company and Pacific Power & Light Company as well as Idaho Power Company and Montana Power Company, which serve southern Idaho and Montana in the region, were controlled by the Electric Bond and Share Company. Through Federal intervention in the 1930's, Electric Bond and Share was divested of control of these and other utilities. A coordinating service which the company provided the private utilities in the Pacific Northwest was continued through the Northwest Power Pool, but in time this function as well was separated from the company.

The Municipal Systems

Tacoma was the first large city of the region to establish municipal ownership. At about the same time, several smaller cities undertook to acquire their own electric systems including Port Angeles, McMinnville, Forest Grove, and Centralia. The

largest municipal utility in the region, and indeed a large one under any standards, has been Seattle City Light. Although empowered by charter to provide street lighting since 1869, the city did not become a power utility until the Charter of March 3, 1896, which provided for ownership and operation of power supply facilities. In time municipal service was provided throughout the city, although not without a series of campaigns involving rate reductions in competition with the private utilities then serving the city.

The city of Eugene became a municipal electric system through its operation of water supply facilities, as have many other systems. In September 1908, the city purchased the existing water system and used the balance of the bond issue to construct the Walterville hydroelectric plant on the McKenzie River. The plant was constructed primarily to provide pumping power, but it provided a surplus for commercial sale. The city then bought out its franchise holder, the Oregon Power Company, in February 1916.

The Cooperative Systems

Electric cooperatives are private, nonprofit enterprises, locally owned and managed, and incorporated under state law. Some of the earliest cooperatives were formed in Southern Idaho over 50 years ago to distribute power from the Government's Minidoka project to small groups of rural customers. Two of the first were Northside Power Company and Rural Electric Cooperative.

The large growth in the cooperative power field came about with the creation of the Rural Electrification Administration by Executive Order of the President on May 11, 1935. The original plan to promote rural electrification was to make low-cost money available to private companies in the electric distribution business. Company research at that time indicated that rural electrification was not economical even with the availability of 2 percent money. Since private companies were not willing to build into rural areas, groups of people began seeking means of getting electricity to their homes. They found the cooperative form of enterprise as a solution to their problem. Over a period of 35 years about 1,000 cooperatives were formed and received loans from the Rural Electrification Administration; 38 of these are located in the region.

Federal Power Development

Federal power development in the eastern part of the region dates back to 1906 when the first hydroelectric power was authorized for construction by the Bureau of Reclamation. The first Federal hydroplant in the region began operation in 1909, as a part of the

Minidoka Reclamation Project in southern Idaho. Continuing reclamation development in Idaho provided hydroelectric power at the Boise Diversion project in 1912, and at Black Canyon in 1925.

In the western part of the region, the Federal Columbia River Power System was added in 1937 to the pattern of mixed private-public ownership. Two Federal generating plants were being completed by that time. Bonneville project was planned by the Corps of Engineers as the first step in developing the navigation of the Lower Columbia River, while Grand Coulee was being constructed by the Bureau of Reclamation as a part of the 1 million-acre Columbia Basin irrigation project of central Washington. Both projects, in addition, provided power for commercial sale. On August 20, 1937, the President signed the Bonneville Project Act. Power to be generated at Bonneville was to receive the widest possible use and the project was to be interconnected with other Federal projects and publicly owned power systems.

Bonneville Power Administration was made the marketing agency for power generated at Grand Coulee by Executive Order of August 26, 1940. The Bonneville and Grand Coulee plants were interconnected at Midway Substation early in 1941. A year later, the first Grand Coulee power was flowing east to Spokane and west over the Cascades to Puget Sound. A line was extended north from Portland to connect with the Grand Coulee line near Seattle, and Walla Walla and Lewiston were linked to Midway. In the course of this development, interconnections were made with the municipalities and private utilities thus setting the stage for eventual coordinated operation.

Following World War II, the Federal Government continued its policy of multipurpose water resource development, and major projects were constructed at McNary, Albeni Falls, Chief Joseph, The Dalles, and in the Willamette Basin (Corps of Engineers' projects) and at Hungry Horse, Anderson Ranch, and Palisades (BR projects). These projects, together with the completion of the initial power installation at Grand Coulee, accounted for nearly two-thirds of the capacity added to the regional power system through the fifties.

Due initially to the budget restraints caused by the Korean war and later to the policies of the administration then in power, Federal hydroelectric development was largely curtailed during the middle and late fifties. Construction continued on projects already well underway, but planning and design were delayed for new projects even though authorized. Because of the long time interval required to design and construct major water resource projects, it was not until the sixties that the effects of this policy were felt. Between 1960 and mid-1968, when the first units went into service at John Day, only 15 percent of the capacity added to the Pacific Northwest power system was Federal.

The "no new starts" policy of the fifties was eventually rescinded and the construction of Federal projects was resumed. Between 1968 and the early seventies, when the first thermal plants will be placed in service, Federal hydro projects will supply most of the region's additional generation requirements. Table 13 lists the projects which make up the Federal Columbia River Power System.

Non-Federal Public Agencies

The Washington public utility districts stepped into the gap created by the lack of newly scheduled Federal generation by requesting licenses for the large mid-Columbia River projects. At the same time financing arrangements were arrived at whereby the capability of such projects was disposed of to other utilities, as the capability of these large plants far exceeds the loads of the licensees. Under such arrangements, construction was started on Priest Rapids in 1956, Rocky Reach in 1957, Wanapum in 1959, and Wells in 1963.

P R E S E N T S I T U A T I O N

The power resources of the region because of current inter-utility contracts and transmission interconnections should be regarded as a unit for planning purposes. The power load of the region should therefore be regarded as a unit for the same reason. In detail this approach is less supportable for some loads and resources than others, but it nevertheless provides a rational analysis.

PRESENT ELECTRIC POWER REQUIREMENTS

United States

The phenomenal growth in the use of electric power in the United States, which on the average has doubled every decade for its 85-year history, is due in large part to the fact that the industry's technological progress has made electricity one of the best bargains available. Its use is taken for granted. Yet without electricity there would be no modern communications, no television or other electronics, no electroprocess industries, and few of the appliances which have become indispensable in most American homes today.

The electric power industry of the United States has grown in capital investment from an infant born in the 1880's to a giant, now the largest in the Nation. Electric power's growth is unmatched in rate and consistency by any other major industry. Production has increased at about twice the rate of increase of overall industrial production. The consistency of this expansion and, especially, the relatively stable flow of expenditures for new electric system plant and equipment have provided a persistent impetus to the Nation's economic growth and have acted as a cushioning force during business recessions.

The electric power industry requires particularly large capital outlays. Its average annual dollar expenditures for plant and equipment are by far the greatest of any industry. In 1968, for example, construction expenditures of the investor-owned segment of the electric utility industry alone amounted to over $7 billion.

Electric energy generation and use in the country increased at an annual compound rate of about 7 percent until, in 1955, the total energy requirements of the country were approximately 635 billion kilowatt-hours. The growth rate in the next decade, 1955-1965,

was slightly lower--averaging about 6.2 percent annually, the Nation's total requirement in 1965 amounting to 1,156 billion kilowatt hours. These total energy requirements and those for 1960 are shown in table 1, broken down by type of use.

The month-by-month variation in energy requirements and peak demand (the annual "load shape") is of importance in scheduling the operation of hydroelectric plants and the maintenance work to be done on all types of generating units. Monthly energy and demand countrywide totals for the major electric power systems for the years 1955, 1960, and 1965 are contained in table 2.

Table 1 - Electric Energy Requirements and Supply of the United States

Electric Energy	1955	1960	1965
		(Million Kilowatt-hours)	
Requirements			
Electric Utility			
Domestic	122,002	189,084	274,246
Commercial	80,657	121,437	188,960
Industrial	258,689	330,484	436,906
Other	37,976	51,634	65,745
Electric Utility Classified -			
Subtotal	499,324	692,639	965,857
Losses	57,920	70,869	91,980
Total, Utility Requirements	557,244	763,508	1,057,837
Industrial Generation for Own Use	77,353 1/	85,184	98,659 1/
Total Requirements	634,597	848,692	1,156,496
Supply			
Electric Utility Generation	548,301	755,375	1,054,813
Industrial Generation	82,228 1/	88,782	101,831
International Energy Transfers			
Imports	4,567	5,323	-
Exports	-499	-788	-
Net Transfers	4,068	4,535	-148
Total, Supply	634,597	848,692	1,156,496

1/ Alaska data incomplete for this year.

Table 2 - Monthly Energy and Peak Demand
Major Electric Power Systems of the United States

Month	1955 Energy	1955 Peak Demand	1960 Energy	1960 Peak Demand	1965 Energy	1965 Peak Demand
	(In Millions of Kilowatt-hours and Millions of Kilowatts)					
January	43,547	84.1	63,185	120.9	86,363	160.6
February	39,936	83.7	59,581	117.4	78,961	160.0
March	44,090	83.4	63,607	116.9	86,422	156.0
April	41,840	82.3	58,139	113.8	80,338	152.9
May	43,160	83.9	59,972	116.3	83,640	160.8
June	43,926	86.5	61,675	122.0	86,255	170.2
July	46,269	89.3	63,306	124.2	91,507	174.3
August	48,830	91.6	66,674	127.8	93,776	178.8
September	45,714	90.1	61,800	126.1	87,452	175.1
October	46,999	90.6	61,282	119.8	85,805	159.7
November	47,465	96.1	60,591	122.2	85,322	167.9
December	50,347	98.3	65,300	128.7	92,059	175.1
Year	542,123	98.3	745,112	128.7	1,037,900	178.8

Pacific Northwest

Compared with the United States, the Columbia-North Pacific region, referred to herein as the Pacific Northwest, has a similarity in annual load factors but has a winter rather than a summer annual peak demand and has a greater per capita energy use.

In the region the 1955 annual load factor was 66 percent. Ten years later it was 65 percent. The national experience was 63 percent in 1955, increasing to 67 percent by 1965.

Maximum annual electric power demands in the Pacific Northwest occur in the winter months. In contrast, summer demands have been greater nationally. Two characteristics help determine the seasonal electric power requirements. The proportion of homes with electric heat is much greater in the Pacific Northwest than nationally, and summer air conditioning is not as important in the region as elsewhere.

Nationally, home electric heating installations were less than 2 percent of the total during 1965. Regionally, 20 percent of the homes had electric heat in 1965. These factors contribute to the differing seasonal patterns in national and regional electric power requirements.

Another difference in regional power use, compared with the Nation, is the much greater per capita annual energy use in the Pacific Northwest. In 1965, the regional per capita consumption was 12,676 kilowatt-hours--more than double the national average of 5,944 kilowatt-hours.

This high per capita consumption results from the availability of low cost hydroelectric power. During 1965, 99 percent of all electric power sold in the region was generated at hydroelectric projects in contrast with 20 percent from this source nationally. Regional wholesale electric power costs are among the lowest in the Nation because of this. The benefits to the area are important. High electric power consuming electroprocess industries have been attracted to the Pacific Northwest. Lower wholesale power costs are furthermore reflected in lower resale rates which also encourage greater residential and commercial consumption.

Annual Energy Loads

Table 3 shows the annual energy requirements in the Pacific Northwest during the 1955-1965 period. The power requirements shown include Oregon, Washington, the 11 counties in western Montana, and all of Idaho, with the exception of the Utah Power & Light Company service area in the southeastern part of the state.

Table 3 - Electric Energy Requirements
Columbia-North Pacific Region

Electric Energy	Total Pacific Northwest 1955	1960	1965
	(Million Kilowatt-hours)		
Sales			
Domestic	11,083	15,941	20,687
Irrigation	1,272	1,671	2,421
Commercial	4,191	6,027	8,781
Industrial	20,876	24,848	34,346
Other	760	815	1,090
Total Sales	38,182	49,302	67,325
Losses	5,229	5,579	7,110
Requirements	43,411	54,881	74,435

Regionally, sales by major consumer classification are generally comparable to the national distribution as shown by table 4. Approximately 31 percent of energy sales went to domestic consumers in the region compared with 28 percent nationally during 1965. Commercial sales were 13 percent in the region and 19 percent nationally, while industrial sales were 51 percent within the region compared with 45 percent nationally. Some of these differences in percentages between commercial and industrial classifications may be due to definition. What is classified as a commercial customer by one distributor may be called an industrial account by another. The combined commercial and industrial percentage is 64 percent both in the Pacific Northwest and nationally.

Table 4 - Energy Sales by Major Sales Categories

Sales Categories	1955 PNW	1955 U.S.	1960 PNW	1960 U.S.	1965 PNW	1965 U.S.
			(Percent)			
Domestic	29	24	32	27	31	28
Commercial	11	16	12	17	13	19
Industrial	55	52	50	48	51	45
Other 1/	5	8	6	8	5	8
Total	100	100	100	100	100	100

1/ Includes street lighting, station use, and irrigation.

Percentage increases in total energy sales by major categories were lower in all instances in the Pacific Northwest when compared with the Nation during 1955-1965. The 1965 sales to domestic consumers were 87 percent higher than 1955 in the region while the national increase was 125 percent. The 1965 energy sales to commercial customers were 110 percent higher than 1955 in the region while the national increase was 134 percent. The 1965 energy sales to industry were 65 percent higher than 1955 in the region while the national increase was 69 percent. Overall

growth in electric energy requirements in the region during 1955-65 was at a 5.7 percent compound annual rate. This was below the national rate of 6.2 percent for the same period.

Percentage increases do not reflect the entire picture since the growth rates are from substantially different levels. The historically greater use per consumer in the Pacific Northwest will continue, although regional and national differences may be less pronounced in the future.

The compound annual rate of increase in number of domestic customers was 2.1 percent in the Pacific Northwest, and 2.4 percent nationally during the 1955-65 period. This reflects the slightly lower population growth rate in the region compared with the Nation. The ratio of population to total domestic customers decreased over the period in the Pacific Northwest as well as in the Nation as follows:

Item	1955	1965
Regional Population	5,074,000	5,871,900
Ratio: Pop./Dom. Cust.	3.3/1	3.1/1
Total U.S. Population	165,931,000	194,572,000
Ratio: Pop./Dom. Cust.	3.7/1	3.4/1

Kilowatt-hour use per domestic customer in the Pacific Northwest was more than double the national average during this period as shown by table 5. Resale rates are among the lowest in the Nation. This has resulted in a high saturation of major electric appliances. Also, active promotion of electric heat installations contributed to the greater use. One in five homes in the region had electric heat by 1965. The reasons for greater regional domestic energy use per customer are better understood from the following comparison between the United States and the Pacific Northwest showing the percent of homes with major electrical appliances.

Such a comparison is made in the following bar chart (figure 1) from data published in the U.S. Census of Housing, 1960 (8). The national relative usage exceeded the region only in air conditioners and television during 1960.

Table 5 - Annual Energy Use per Domestic Customer

Year	United States	Pacific Northwest
	(Kilowatt hours)	
1955	2,773	7,267
1960	3,854	9,465
1965	4,993	11,011

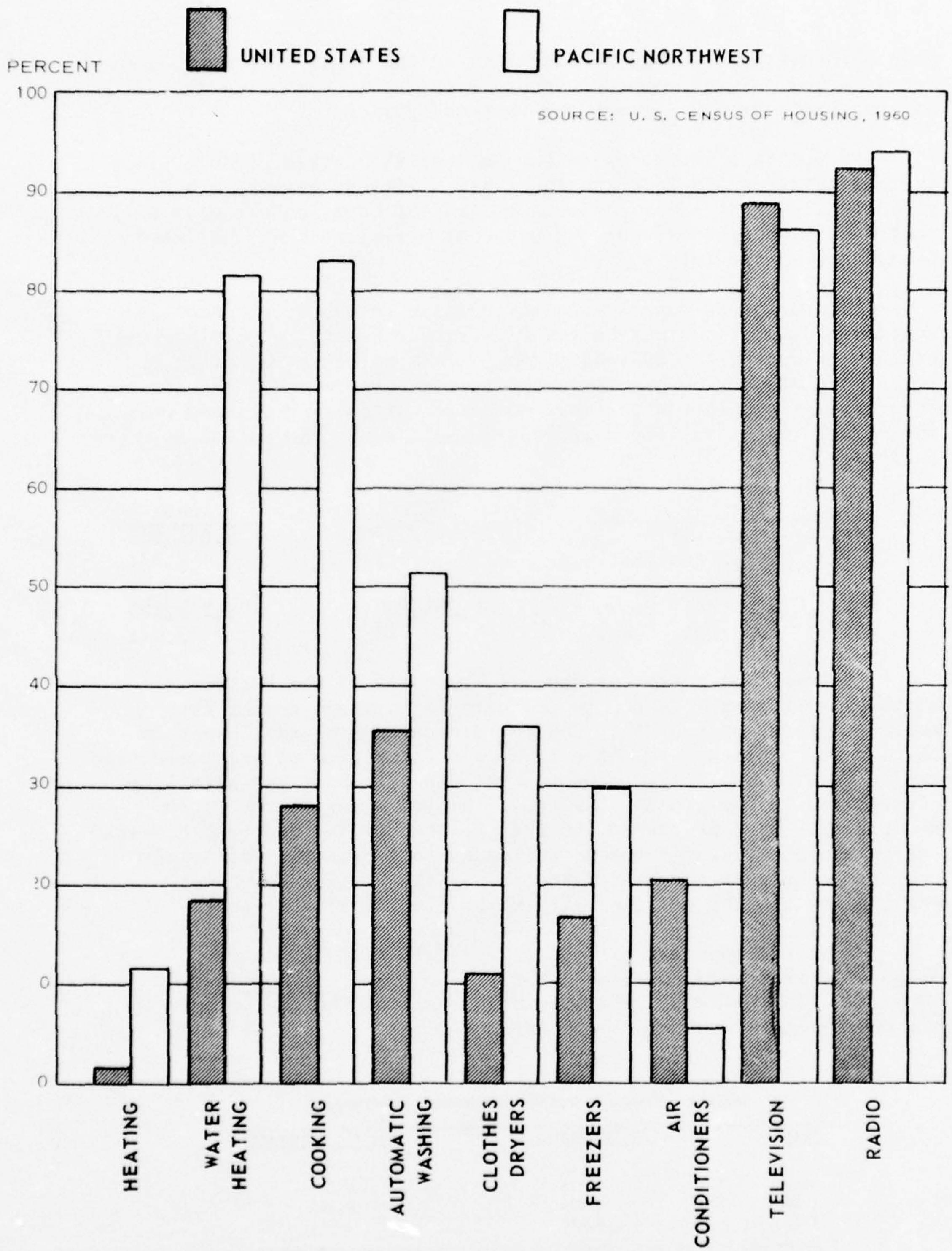


FIGURE 1. Major Electrical Appliance Saturation, 1960

Commercial energy use per customer has also been consistently greater in the area during this period as shown by table 6. Improved lighting, electric heating, and air conditioning of new office buildings have contributed to this growth. The trend toward larger shopping centers and fewer smaller enterprises also is evident during this decade.

Table 6 - Annual Energy Use per Commercial Customer

Year	United States	Pacific Northwest
	(Kilowatt-hours)	
1955	12,656	20,556
1960	17,006	26,625
1965	27,399	36,607

Energy sales to industry in the region accounted for 51 percent of the total sales in 1965. Heaviest power users in the region include the aluminum industry, pulp and paper manufacturing, nonferrous metal mining and refining, and the phosphate industry. Approximately 30 percent of the national aluminum reduction capacity is located in the area. Sales to industry are shown in table 7.

Table 7 - Total Industrial Sales

Year	United States	Pacific Northwest	Pacific Northwest in Percent of United States
	(Million Kilowatt-hours)		
1955	258,689	20,876	8.1
1960	330,484	24,848	7.5
1965	436,906	34,346	7.8

Both nationally and regionally, industrial sales as a percent of total sales have declined during the 1955-65 period. Some of this apparent decline may be due to reclassification between commercial and industrial accounts.

Irrigation sales in the region during 1965 were 3.6 percent of total annual energy sales. Although this is a small amount of the total regional sales, it is highly significant in several local areas. Almost 15 percent of the sales in southern Idaho and over 10 percent in northeast Washington were used for irrigation during 1965. Improvements in pumps and sprinkler irrigation equipment have made possible the delivery of water to land never before considered irrigable. Consequently, more economically marginal land is being reclaimed and irrigated. Plans to lift water 800 to 1,000 feet to lands previously not classified as irrigable will increase the pumping load substantially. A second noticeable trend in irrigation is the extension of the season beyond the 2 or 3-month period to as much as 10 months for improved crop production. These two factors will assure an increase in electric power sales in the coming years.

Other sales include street and highway lighting. Less than 2 percent of total sales were in this category during 1965. Although this category as a percent of total sales in the region was declining during the 1955-65 period, the 1965 sales were 40 percent more than the 1955 level.

Monthly Peak and Energy Loads

Electric utility loads have become increasingly sensitive to temperature variation in recent years due to space heating. By 1965, the load response was almost 1 percent per degree Fahrenheit in the Pacific Northwest. For example, a 10-degree drop in temperature will increase the load approximately 9 percent. During 1965, the total regional load response to temperature approximated 82,000 kilowatts per degree. Thus a 10-degree drop in temperature would increase the area load by 820,000 kilowatts. The temperature response causes some variation in load shapes from year to year. In some local areas summer irrigation loads are important in determining the annual load shape.

Monthly peak and energy loads listed in table 9 are shown in percent of annual requirements in table 8. For comparative purposes, the loads shown in table 9 are also shown on figure 2.

Table 8 - Monthly Energy and Peak Requirements
Major Electric Power Systems, Columbia-North Pacific Region

Month	1955 Energy	1955 Peak	1960 Energy	1960 Peak	1965 Energy	1965 Peak
	(Percent of Annual Requirements)					
January	8.35	86.65	9.11	100.00	9.05	90.61
February	7.54	84.19	8.25	94.98	8.00	87.46
March	8.37	82.65	8.71	98.17	8.50	85.80
April	7.84	80.74	8.07	88.64	7.92	82.40
May	7.97	79.48	8.57	89.74	8.21	84.33
June	8.09	82.09	7.75	85.55	7.87	80.16
July	8.00	78.46	8.00	83.24	7.98	77.73
August	8.31	80.03	8.16	85.78	8.12	79.56
September	8.20	84.67	7.68	84.76	7.86	84.10
October	8.54	88.87	8.08	88.14	8.24	84.36
November	9.22	100.00	8.43	97.60	8.55	92.56
December	9.57	98.08	9.19	98.87	9.70	100.00
Year	100.00		100.00		100.00	

Total Regional Electric Loads

Table 10 summarizes annual peak and energy requirements for the region along with other related data discussed above for the 1955-1965 period. Minor differences in totals will be noted when total energy sales shown on table 10 are compared with totals on

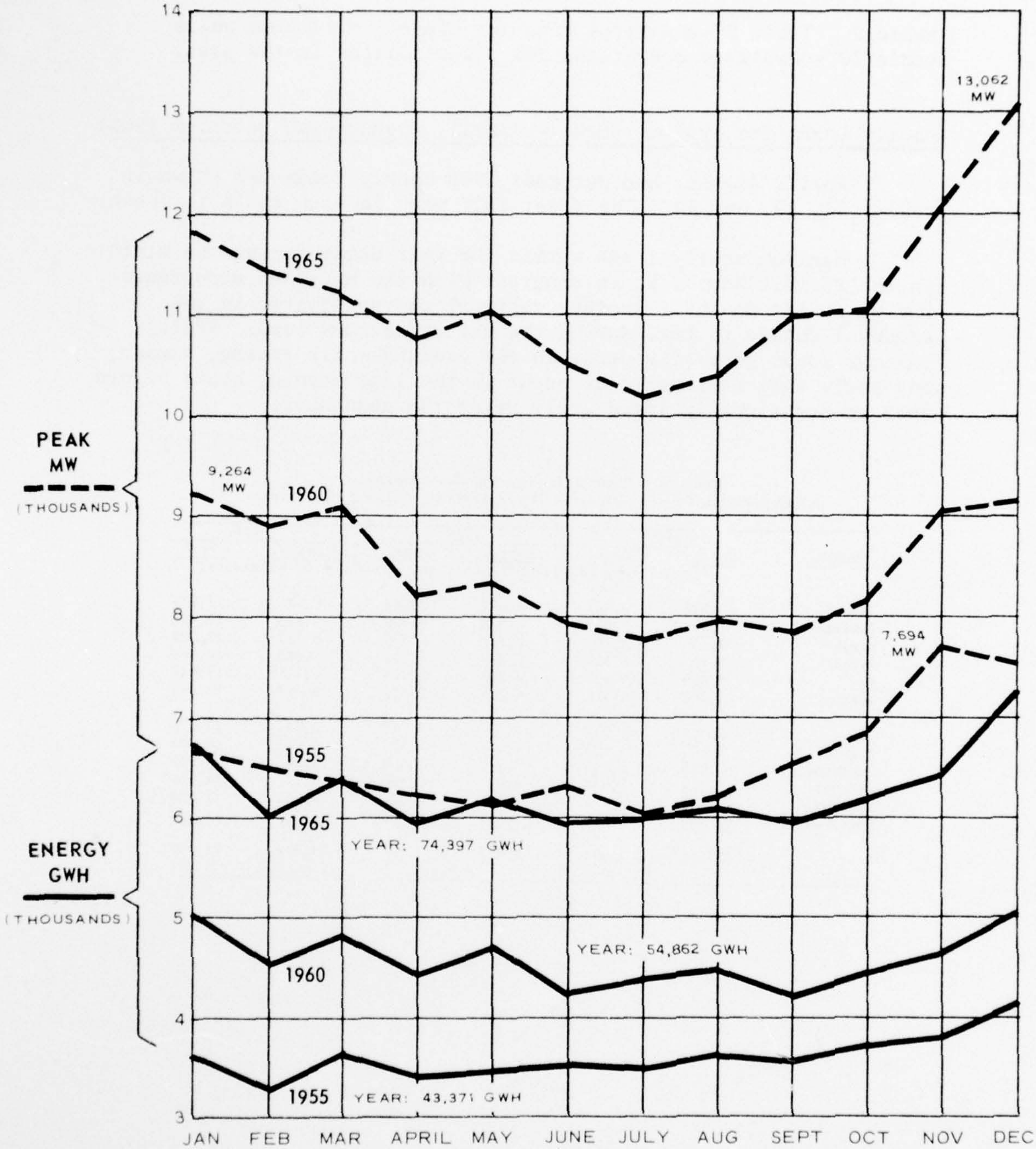


FIGURE 2. Major Electric Power Systems of the Pacific Northwest Monthly Energy and Peak Demand (1955 - 1960 - 1965)

table 9. Table 9 summarizes data for Class I utilities while table 10 summarizes operations for all utilities in the area.

Hourly Loads for Typical Weeks - (April, August, and December 1965)

April, August, and December 1965 hourly loads are shown in tables 11, 12, and 13. The first full week in each month is shown.

Maximum hourly loads within the year occur during the winter in the Pacific Northwest in contrast with the national occurrence during summer months. Another regional characteristic is the seasonal change in time during the day of maximum load. Winter maximum loads generally occur in the evening while spring, summer, and early fall maximum loads occur in the late morning hours before noon or occasionally immediately after the noon hour.

Table 9 - Monthly Energy and Peak Demand
Columbia-North Pacific Electric Power Systems, Class I Utilities

Month	1955		1960		1965	
	Energy	Peak	Energy	Peak	Energy	Peak
	(in millions of kilowatt-hours and thousands of kilowatts)					
January	3,623	6,667	4,998	9,264	6,736	11,835
February	3,271	6,478	4,528	8,799	5,953	11,424
March	3,630	6,359	4,778	9,095	6,323	11,207
April	3,401	6,212	4,430	8,212	5,883	10,763
May	3,458	6,115	4,704	8,314	6,111	11,015
June	3,508	6,316	4,250	7,926	5,857	10,471
July	3,469	6,037	4,387	7,712	5,941	10,153
August	3,606	6,158	4,479	7,947	6,038	10,392
September	3,555	6,515	4,215	7,853	5,846	10,985
October	3,704	6,838	4,431	8,166	6,130	11,019
November	3,997	7,694	4,623	9,042	6,362	12,090
December	4,149	7,546	5,039	9,160	7,217	13,062
Year	43,371	7,694	54,862	9,264	74,397	13,062

Table 10 - Population and Electric Power Use
Columbia-North Pacific Region, All Utilities

Item	1955	1960	1965
Population	5,074,000	5,489,729	5,871,900
Ratio: Pop./Dom. Cust.	3.3/1	3.2/1	3.1/1
Domestic Customers	1,525,116	1,684,173	1,878,814
KWH Use Per Dom. Cust.	7,267	9,465	11,011
Total Domestic Use-GWH[1/]	11,083	15,941	20,687
Ratio: Pop./Com. Cust.	24.9/1	24.2/1	24.5/1
Commercial Customers	203,885	226,363	239,883
KWH Use Per Com. Cust.	20,556	26,625	36,607
Total Com. Use-GWH	4,191	6,027	8,781
Industrial Customers	6,621	6,373	6,486
Industrial Use-KWH Per Capita	4,114	4,526	5,936
Total Industrial Use-GWH	20,876	24,848	34,346
Irrigation Use-GWH	1,272	1,671	2,421
Other Use-GWH	760	815	1,090
Total Sales-GWH	38,182	49,302	67,325
Losses-GWH	5,229	5,579	7,110
Total Requirements-GWH	43,411	54,881	74,435
Per Capita Use-KWH	8,556	9,997	12,676
Peak Use-MW	7,555	9,164	13,068
Energy Use-Avg. MW	4,956	6,265	8,497
Load Factor-Percent	65.6	68.4	65.0

1/ Million KWH.

Table 11 - Regional Hourly Load, April 1965, Columbia-North Pacific Region

Hour	Sunday	Monday	Tuesday	Wednesday (Megawatts)	Thursday	Friday	Saturday
1	6,953	6,594	7,197	7,252	7,066	7,004	7,164
2	6,640	6,340	6,930	6,965	6,772	6,552	6,807
3	6,468	6,283	6,774	6,764	6,635	6,327	6,569
4	6,374	6,278	6,722	6,661	6,552	6,304	6,533
5	6,414	6,405	6,822	6,788	6,609	6,381	6,519
6	6,455	6,805	7,236	7,189	7,017	6,778	6,748
7	6,685	7,835	8,316	8,243	8,054	7,747	7,249
8	7,227	9,293	9,630	9,542	9,294	9,137	8,092
9	7,867	10,015	10,190	9,977	9,759	9,856	8,870
10	8,047	10,251	10,268	9,996	9,850	9,969	9,217
11	8,030	10,361	10,234	9,863	9,664	9,933	9,309
12	7,948	10,072	9,943	9,544	9,347	9,651	9,178
13	8,339	9,757	9,802	9,269	9,089	9,479	8,359
14	8,107	9,753	9,743	9,182	9,081	9,496	8,166
15	7,802	9,601	9,522	8,985	8,807	9,208	7,899
16	7,570	9,488	9,498	8,858	8,821	9,188	7,759
17	7,626	9,533	9,550	8,893	8,850	9,211	7,860
18	8,015	9,844	9,809	9,158	9,235	9,477	8,139
19	8,653	10,041	9,945	9,400	9,388	9,707	8,373
20	9,113	10,143	10,206	9,696	9,649	9,819	8,677
21	9,069	9,702	9,839	9,495	9,370	9,442	8,576
22	8,783	9,169	9,338	9,014	8,832	8,890	8,191
23	8,078	8,551	8,590	8,260	8,163	8,358	7,697
24	7,355	7,748	7,845	7,573	7,559	8,051	7,197

Total: 1,412,572 megawatt-hours
Weekly Average: 8,408.2 megawatt-hours

Table 12 - Regional Hourly Load, August 1965, Columbia-North Pacific Region

Hour	Sunday	Monday	Tuesday	Wednesday (Megawatts)	Thursday	Friday	Saturday
1	6,130	6,124	6,544	6,536	6,630	6,636	6,612
2	5,994	5,997	6,257	6,307	6,364	6,362	6,333
3	5,823	5,922	6,140	6,220	6,274	6,228	6,177
4	5,788	5,900	6,069	6,193	6,223	6,257	6,093
5	5,717	6,005	6,190	6,376	6,423	6,401	6,145
6	5,772	6,462	6,739	6,920	6,934	6,943	6,345
7	6,102	7,432	7,794	7,853	7,936	7,900	6,862
8	6,691	8,414	8,690	8,725	8,722	8,669	7,588
9	7,157	9,122	9,111	9,260	9,254	9,176	8,290
10	7,507	9,528	9,428	9,510	9,487	9,522	8,546
11	7,651	9,590	9,407	9,558	9,466	9,453	8,728
12	7,675	9,548	9,281	9,411	9,325	9,277	8,688
13	7,498	9,631	9,276	9,404	9,385	9,271	8,455
14	7,334	9,446	9,157	9,253	9,239	9,166	8,367
15	7,167	9,281	9,011	9,083	9,094	8,999	8,144
16	7,144	9,102	8,858	8,912	8,905	8,817	8,115
17	7,216	9,153	9,005	8,985	8,914	8,852	8,177
18	7,324	9,020	8,850	8,890	8,775	8,759	8,096
19	7,335	8,900	8,690	8,721	8,598	8,621	7,985
20	7,549	8,879	8,713	8,750	8,665	8,635	8,109
21	7,818	8,820	8,793	8,841	8,803	8,744	8,213
22	7,528	8,298	8,292	8,376	8,414	8,361	7,830
23	6,926	7,577	7,593	7,674	7,733	7,753	7,216
24	6,418	6,909	6,953	6,959	7,088	7,050	6,738

Total: 1,326,235 megawatt-hours
Weekly Average: 7,894.3 megawatt-hours

Table 13 - Regional Hourly Load, December 1965, Columbia-North Pacific Region

Hour	Sunday	Monday	Tuesday	Wednesday (Megawatts)	Thursday	Friday	Saturday
1	7,232	7,031	7,253	7,503	7,607	7,633	7,950
2	6,897	6,705	6,975	7,132	7,273	7,297	7,503
3	6,650	6,623	6,750	6,957	7,065	7,045	7,262
4	6,558	6,516	6,706	6,891	7,042	6,947	7,184
5	6,483	6,608	6,732	6,972	7,158	7,045	7,171
6	6,608	6,997	7,145	7,439	7,535	7,514	7,372
7	6,841	8,094	8,250	8,635	8,702	8,646	7,864
8	7,298	9,719	9,783	10,143	10,269	10,190	8,691
9	8,150	10,407	10,318	10,696	10,861	10,929	9,669
10	8,701	10,658	10,465	10,732	10,949	11,063	10,246
11	8,956	10,564	10,320	10,613	10,840	10,955	10,380
12	9,066	10,211	9,980	10,214	10,496	10,628	10,325
13	9,105	9,952	9,768	9,917	10,236	10,383	10,124
14	8,965	9,822	9,817	9,910	10,183	10,389	9,894
15	8,856	9,605	9,668	9,779	10,085	10,170	9,748
16	8,824	9,729	9,767	9,876	10,236	10,219	9,760
17	9,305	10,367	10,403	10,560	10,898	10,820	10,429
18	9,744	11,012	11,030	11,177	11,445	11,368	10,976
19	9,587	10,734	10,856	11,023	11,223	11,195	10,811
20	9,484	10,437	10,597	10,830	10,912	10,801	10,466
21	9,334	10,006	10,216	10,333	10,484	10,404	10,048
22	8,953	9,464	9,701	9,763	9,877	9,846	9,579
23	8,350	8,787	8,942	9,074	9,138	9,358	9,064
24	7,546	7,942	8,108	8,261	8,301	8,616	8,315

Total: 1,538,569 megawatt-hours
Weekly Average: 9,158.2 megawatt-hours

EXISTING ELECTRIC POWER RESOURCES

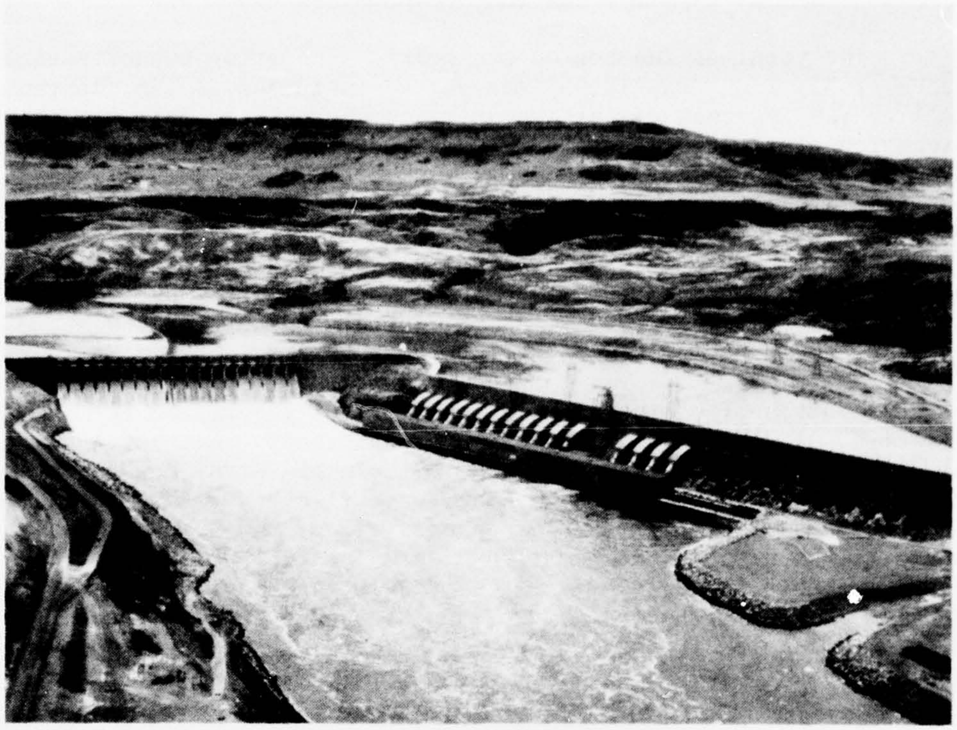
The total of the region's electric generating capacity as of December 31, 1969, was 18,963 megawatts, installed at 186 plants. Well over 90 percent of this capacity is hydroelectric. With the exception of the 800 megawatt Hanford nuclear plant, most of the thermal capacity is old and normally used only as reserves. In addition, there is under construction 8,353 megawatts of capability, about 70 percent of which is hydroelectric. A large share of the hydro capacity currently under construction consists of expansion of existing projects. Two large thermal plants are under construction, the coal-fired 1,400 megawatt Centralia plant and the 1,106 megawatt nuclear Trojan plant, near Rainier, Oregon.

About half of the existing capacity of the region is installed at Federal multipurpose hydro projects. All but a few minor plants are a part of the Federal Columbia River Power System, whose production is marketed by the Bonneville Power Administration. The BPA transmission grid interconnects all of the System plants except five Bureau of Reclamation plants located in southern Idaho. In addition to the 8,496 megawatts of existing capacity, there are 7,263 megawatts of Federal hydro capacity under construction. The Federal Columbia River Power System projects are summarized on table 14.

The balance of the region's power resources is under the ownership of the public and private utilities. Table 15 summarizes all of the region's power resources by utility.

The non-Federal utilities within the Columbia-North Pacific Region have 120 hydroelectric projects with an installed hydroelectric capacity of about 9,188 megawatts. Added capacity of 501.6 megawatts is being installed at the Rocky Reach project of Chelan County PUD. The non-Federal utilities have 29 thermal electric plants with an installed capacity of 1,239 megawatts of which 64 percent is at the nuclear plant at Hanford. The remaining plants operate only in years when the power system approaches a deficiency condition. These generating capacities are summarized by utilities on table 15.

The bulk of the generating capacity of the area lies on the main Columbia River where the plants are both Federally and non-Federally owned. The firm capabilities of these plants are greatly enhanced by reservoir storage. Table 16 is a summary of the reservoirs which provide this regulation, their programmed storage release, and the gain in energy which they provide over the 8-month critical streamflow period at site and to downstream plants under 1968-69 conditions. The firm power capability of the region, particularly on the main Columbia River, is greatly enhanced by reservoir storage. Table 16 summarizes the reservoir storage of



Chief Joseph Dam, a run-of-river hydroelectric plant is located on the Columbia River in Washington (Corps of Engineers).

the Columbia River Power System. As shown, the total usable storage at 33 reservoirs is 28,469,000 acre-feet. All this storage is operated in direct coordination for the Columbia River Power System. In addition, there are reservoirs less directly coordinated, but which nevertheless provide power benefits from storage. Minor miscellaneous storage is operated by the power utilities and power storage in the following amounts is operated by the Bureau of Reclamation at reservoirs constructed principally for nonpower purposes.

Palisades	1,202,000 acre-feet
American Falls	45,000 acre-feet
Minidoka	95,000 acre-feet
Anderson Ranch	423,000 acre-feet
Cascade	653,000 acre-feet
Total	2,418,000 acre-feet

With the power storage on table 16, all power capability of the region can be fitted to firm load with recurrence of historical streamflows over the period August 16, 1936, through April 15, 1937. When Mica Reservoir is completed, this critical period will extend to a period at or near the 43 months of September 1928 through

Table 14 - Federal Columbia River Power System General Specifications, Projects Existing, Under Construction and Authorized Nameplate Rating of Intallations as of December 31, 1969

Project	Operating Agency1/	Location	Stream	Existing: Initial Date in Service	Existing: Number of Units	Existing: Total Capacity Kilowatts	Under Construction: Number of Units	Under Construction: Total Capacity Kilowatts	Authorized: Number of Units	Authorized: Total Capacity Kilowatts	Total: Number of Units	Total: Total Capacity Kilowatts
Bonneville	CE	Ore.-Wash.	Columbia	June 1938	10	518,400	-	-	6	480,000	16	998,400
Grand Coulee	BR	Washington	Columbia	Sept. 1941	18	2,042,000 2/	6	3,838,000 3/	-	-)	30	6,171,000
Grand Coulee (Pump Turbines)		Washington	Columbia		-	-	2	97,000	4	194,000)		
Hungry Horse	BR	Montana	S. Fk. Flathead	Oct. 1952	4	285,000	-	-	-	-	4	285,000
Detroit	CE	Oregon	North Santiam	July 1953	2	100,000	-	-	-	-	2	100,000
McNary	CE	Ore.-Wash.	Columbia	Nov. 1953	14	980,000	-	-	-	-	14	980,000
Big Cliff	CE	Oregon	North Santiam	June 1954	1	18,000	-	-	-	-	1	18,000
Lookout Point	CE	Oregon	M. Fk. Willamette	Dec. 1954	3	120,000	-	-	-	-	3	120,000
Albeni Falls	CE	Idaho	Pend Oreille	Mar. 1955	3	42,600	-	-	-	-	3	42,600
Dexter	CE	Oregon	M. Fk. Willamette	May 1955	1	15,000	-	-	-	-	1	15,000
Chief Joseph	CE	Washington	Columbia	Aug. 1955	16	1,024,000	-	-	11	1,045,000	27	2,069,000
Chandler	BR	Washington	Yakima	Feb. 1956	2	12,000	-	-	-	-	2	12,000
The Dalles	CE	Ore.-Wash.	Columbia	May 1957	16	1,119,000	8	688,000	-	-	24	1,807,000
Roza	BR	Washington	Yakima	Aug. 1958	1	11,250	-	-	-	-	1	11,250
Ice Harbor	CE	Washington	Snake	Dec. 1961	3	270,000	-	-	3	332,880	6	602,880
Hills Creek	CE	Oregon	M. Fk. Willamette	May 1962	2	30,000	-	-	-	-	2	30,000
Minidoka	BR	Idaho	Snake	May 1909	7	13,400	-	-	-	-	7	13,400
Boise Diversion	BR	Idaho	Boise	May 1912	3	1,500	-	-	-	-	3	1,500
Black Canyon	BR	Idaho	Payette	Dec. 1925	2	8,000	-	-	-	-	2	8,000
Anderson Ranch	BR	Idaho	S. Fk. Boise	Dec. 1950	2	27,000	-	-	1	13,500	3	40,500
Palisades	BR	Idaho	Snake	Feb. 1957	4	114,000	-	-	-	-	4	114,000
Cougar	CE	Oregon	S. Fk. McKenzie	Feb. 1964	2	25,000	-	-	1	35,000	3	60,000
Green Peter	CE	Oregon	Middle Santiam	June 1967	2	80,000	-	-	-	-	2	80,000
Foster	CE	Oregon	South Santiam	Aug. 1968	2	20,000	-	-	-	-	2	20,000
John Day	CE	Ore.-Wash.	Columbia	July 1968	10	1,350,000	6	810,000	4	540,000	20	2,700,000
Lower Monumental	CE	Washington	Snake	May 1969	2	270,000	1	135,000	3	405,000	6	810,000
Little Goose	CE	Washington	Snake		-	-	3	405,000	3	405,000	6	810,000
Lower Granite	CE	Washington	Snake		-	-	3	405,000	3	405,000	6	810,000
Teton	BR	Idaho	Teton		-	-	2	16,000	-	-	2	16,000
Lost Creek	CE	Oregon	Rogue		-	-	2	49,000	-	-	2	49,000
Dworshak	CE	Idaho	N. Fk. Clearwater		-	-	3	400,000	3	660,000	6	1,060,000
Strube	CE	Oregon	S. Fk. McKenzie		-	-	-	-	1	4,500	1	4,500
Libby	CE	Montana	Kootenai		-	-	4	420,000	4	420,000	8	840,000
Asotin	CE	Wash.-Ida.	Snake		-	-	-	-	4	540,000	4	540,000
Total installed capacity						8,496,150		7,263,000		5,479,880		21,239,030
Total number of projects						25		6		2		33

1/ CE--Corps of Engineers; BR--Bureau of Reclamation.
2/ Includes three service units and increase of 17,000 kw each for four rewound main units.
3/ Includes an increase of 17,000 kw each for 14 units to be rewound and six 600,000 kw units being installed at the Third Powerplant.

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Table 15 - System Capacities of Projects Existing, Under Construction, and Authorized or Licensed, Columbia-North Pacific Region, December 31, 1969

CLASS Utility	HYDRO Existing No. of Plants	HYDRO Existing Nameplate Rating-KW	HYDRO Construction No. of Plants	HYDRO Construction Nameplate Rating-KW	HYDRO Authorized or Licensed No. of Plants	HYDRO Authorized or Licensed Nameplate Rating-KW	HYDRO Total No. of Plants	HYDRO Total Nameplate Rating-KW	THERMAL Existing No. of Plants	THERMAL Existing Nameplate Rating-KW	TOTAL EXISTING No. of Plants	TOTAL EXISTING Nameplate Rating-KW	GRAND TOTAL No. of Plants	GRAND TOTAL Nameplate Rating-KW
FEDERAL														
Bureau of Indian Affairs	1	360	0	0	0	0	1	360	0	0	1	360	1	360
Bureau of Reclamation	1	16,000	0	0	0	0	1	16,000	0	0	1	16,000	1	16,000
Columbia River Power System	25	8,496,150	6	7,263,000	2	5,479,880	33	21,239,030	0	0	25	8,496,150	33	21,239,030
National Park Service	1	800	0	0	0	0	1	800	6	562	7	1,362	7	1,362
Navy Yard Yard	0	0	0	0	0	0	0	0	1	18,000	1	18,000	1	18,000
Wapato Irrigation District	2	3,360	0	0	0	0	2	3,360	0	0	2	3,360	2	3,360
FEDERAL TOTALS	30	8,516,670	6	7,263,000	2	5,479,880	38	21,259,550	7	18,562	37	8,535,232	45	21,278,112
NON-FEDERAL														
Public														
Baker, City of	1	120	0	0	0	0	1	120	0	0	1	120	1	120
Bonners Ferry, City of	2	2,380	0	0	0	0	2	2,380	1	240	3	2,620	3	2,620
Centralia, City of	1	9,000	0	0	0	0	1	9,000	0	0	1	9,000	1	9,000
Chelan County PUD	4	971,850	0	501,600	0	398,000	4	1,871,450	1	150	5	972,000	5	1,871,600
Cowlitz County PUD	1	70,000	0	0	0	0	1	70,000	1	26,640	2	96,640	2	96,640
Douglas County PUD	1	774,250	0	0	0	0	1	774,250	0	0	1	774,250	1	774,250
Eugene, City of	4	111,500	0	0	0	0	4	111,500	1	26,875	5	138,375	5	138,375
Fall River Rural Electric Coop.	1	1,870	0	0	0	0	1	1,870	0	0	1	1,870	1	1,870
Grant County PUD	2	1,619,750	0	0	0	971,850	2	2,591,600	0	0	2	1,619,750	2	2,591,600
Grays Harbor County PUD	0	0	0	0	0	0	0	0	1	12,500	1	12,500	1	12,500
Idaho Falls, City of	3	7,400	0	0	0	0	3	7,400	1	2,500	4	9,900	4	9,900
Lower Valley Power & Light, Inc.	3	2,900	0	0	0	0	3	2,900	3	1,560	6	4,460	6	4,460
McMinnville, City of	0	0	0	0	0	0	0	0	1	2,740	1	2,740	1	2,740
Orcas Power & Light Coop.	0	0	0	0	0	0	0	0	2	2,310	2	2,310	2	2,310
Pend Oreille County PUD	2	60,560	0	0	0	0	2	60,560	0	0	2	60,560	2	60,560
Seattle, City of	5	1,188,256	1	2,000	0	395,500	6	1,585,756	2	51,000	7	1,239,256	8	1,636,756
Snohomish County PUD	0	0	0	0	3	140,000	3	140,000	0	0	0	0	3	140,000
Spokane, City of	1	3,900	0	0	0	0	1	3,900	0	0	1	3,900	1	3,900
Tacoma, City of	6	659,700	0	0	0	190,500	6	850,200	2	59,000	8	718,700	8	909,200
Washington Public Power Supply System	1	26,125	0	0	0	0	1	26,125	1	800,000	2	826,125	2	826,125
Public Totals	38	5,509,561	1	503,600	3	2,095,850	42	8,109,011	17	985,515	55	6,495,076	59	9,094,526
Private														
Atlanta Power Co.	1	150	0	0	0	0	1	150	0	0	1	150	1	150
California-Pacific Utilities Co.	1	800	0	0	0	0	1	800	0	0	1	800	1	800
Clearwater Power Co.	0	0	0	0	0	0	0	0	1	493	1	493	1	493
Idaho Power Co.	17	1,289,345	0	0	0	398,200	17	1,687,545	1	6,825	18	1,296,170	18	1,694,370
Montana Light & Power Co.	2	4,500	0	0	0	0	2	4,500	2	15,550	4	20,050	4	20,050
Montana Power Co.	4	202,140	0	0	0	0	4	202,140	0	0	4	202,140	4	202,140
Pacific Power & Light Co.	28	712,747	0	0	0	153,000	28	865,747	5	65,300	33	778,047	33	931,047
Portland General Electric Co.	8	534,350	0	0	0	25,500 1/	8	559,850	1	75,500	9	609,850	9	635,350
Puget Sound Power & Light Co.	7	290,690	0	0	0	114,600	7	405,290	2	90,000	9	380,690	9	495,290
Utah Power & Light Co.	2	6,300	0	0	0	0	2	6,300	0	0	2	6,300	2	6,300
Washington Water Power Co.	10	636,530	0	0	0	70,720	10	707,250	0	0	10	636,530	10	707,250
Western Light & Power Co.	2	1,150	0	0	0	0	2	1,150	0	0	2	1,150	2	1,150
Private Totals	82	3,678,702	0	0	0	762,020	82	4,440,722	12	253,668	94	3,932,370	94	4,694,390
NON-FEDERAL TOTALS	120	9,188,263	1	503,600	3	2,857,870	124	12,549,333	29	1,239,183	149	10,427,446	153	13,788,916
COLUMBIA-NORTH PACIFIC TOTALS	150	17,704,933	7	7,766,600	5	8,337,750	162	33,809,283	36	1,257,745	186	18,962,678	198	35,067,028

1/ Application to Federal Power Commission pending for abandonment of license.

March 1932. Studies show that hydroelectric capability outside this period will be no less than this critical period capability. In many months there will be considerable additional energy to meet secondary loads.

As all generating utilities in the west part of the region operate in close coordination, their capabilities under such coordination measure the loads that they can carry. Table 16 shows that these utilities had a collective firm energy load carrying capability for the 1969-70 contract year of 11,611,100 average kilowatts. This is for a critical storage release period of August 16 through April 15. As there is a 683,300-kilowatt surplus of peaking capability in the system, while energy loads and resources are in balance, this energy capability measures the firm load that the system can carry. The amounts for individual utilities on table 17 reflect sales of firm power between the utilities and, therefore, are not a measure of individual utility generating capability.

Table 16 - Storage Reservoirs, Columbia River Power System, 1970-71

River Basin	Reservoir	Usable Storage Content (1,000 ac-ft)
Columbia	Arrow	7,145
	Duncan	1,411
	Kootenay Lake	565
	Hungry Horse	3,161
	Flathead Lake	1,219
	Noxon Rapids	231
	Priest Lake	70
	Albeni Falls	1,155
	Coeur d'Alene Lake	223
	Long Lake	104
	Grand Coulee	5,232
	Lake Chelan	677
	Brownlee	980
	John Day	535
	Round Butte	274
Lower Columbia	Swift #1	447
	Yale	190
	Merwin	115
	Packwood Lake	3
	Mossyrock	1,298
Puget Sound	Cushman	372
	Alder	180
	White River	43
	Ross	1,052
	Upper Baker	185
	Lower Baker	142
Willamette	Hills Creek	244
	Lookout	337
	Cougar	154
	Green Peter	313
	Foster	29
	Detroit	321
	Timothy Lake	62
TOTAL		28,469

The system operated by the parties to the Coordination Agreement is smaller than the region in that the hydroelectric resources in southern Idaho are omitted. Adding the capability of Idaho Power Company and the Federal Upper Snake River projects in the amount of 827,000 kilowatts, the firm energy load carrying capability of the Columbia-North Pacific Region for 1969-70 is 12,438,100 kilowatts.

Table 17 - Pacific Northwest Coordination Agreement
Firm Energy Load-Carrying Capability, 1969-70

	Average Megawatts
United States Columbia River System	6,407.9
City of Eugene	44.7
City of Seattle	728.3
City of Tacoma	389.8
Grant County PUD	29.8 1/
Chelan County PUD	38.8 1/
Pend Oreille County PUD	59.9
Douglas County PUD	0.0 1/
Cowlitz County PUD	0.0 1/
Puget Sound Power & Light Co.	1,136.7
Portland General Electric Co.	807.9
Pacific Power & Light Co.	1,055.7
The Washington Water Power Co.	604.6
The Montana Power Co.	183.0
Colockum Transmission Co.	124.0
Total	11,611.1

1/ Amount remaining after sale of firm capability to other listed utilities.

EXISTING TRANSMISSION FACILITIES

A vast network of transmission circuits links generating plants to load centers in the region. Transmission circuit voltages range from 69 kilovolts to 500 kilovolts. In some areas, the lower voltage circuits may be considered transmission circuits, while circuits of the same voltage in other areas are considered to be subtransmission or even distribution circuits. In general, at the present time, circuits at the 115-kilovolt level and higher are considered to be transmission circuits. Circuits of 230 kilovolts and even higher are coming into increasingly common use, however, for intrasystem and subtransmission networks.

A recent survey of the systems of the Northwest Power Pool indicates approximately 12,000 miles of transmission circuits rated 230 kilovolts or higher in service in 1967. Most of these circuits are in the Columbia-North Pacific Region. A breakdown of these circuits by voltage categories is as follows:

230 kilovolts-345 kilovolts	11,100 miles
500 kilovolts and higher	980 miles

These lines operate most of the time without manual intervention through a highly sophisticated communication system. For example, it is estimated that 38,000 relays are in service in the region to provide protection for generating facilities and transmission circuits.

By the end of 1970, an additional 3,700 miles of transmission line rated 230 kilovolts or higher were added to the Northwest Grid. Approximately one-third of these lines were of 500 kilovolts or higher. This includes the Northwest portion, 265 miles, of the 800 kilovolt direct-current line between The Dalles and Los Angeles. Right-of-way requirements for these and projected lines are making serious inroads in timber, agricultural, and populated areas. However, the use of higher transmission voltages materially reduces the land requirements measured in terms of acres per kilowatt transmitted. For example, a 500-kilovolt line of modern design will transmit in the order of five times the power normally carried by a 230-kilovolt line, with little or no increase in right-of-way requirements, 125-150 feet in width for the 500-kilovolt line, as compared with 125 feet for the 230-kilovolt line. In addition, unlike right-of-way for highways and roads, some production can be sustained on land occupied by transmission lines.

The location and characteristics of the hydro power supply, the interdependence of electrical and hydraulic coordination and the many transactions between systems in the form of sales, purchases, and exchanges have resulted in a multitude of interconnections between the major generating systems. Figure 3 shows these interconnections in diagrammatical form. These interconnections have been made at practically every transmission and subtransmission voltage level. A few of those which are shown were completed before 1930. In addition to these interconnections between the major systems, there are many more with the smaller nongenerating systems, particularly between Bonneville Power Administration and these systems. These additional interconnections are made at all voltage levels but generally at or below 115 kilovolts.

In addition to the many system interconnections within the region, there are interconnections with other regions. In 1958, the Northwest Power Pool was interconnected with the Rocky Mountain Power Pool. Further interconnections were made in 1964, when the Pacific Southwest and New Mexico areas were interconnected with the Northwest Power Pool and the Rocky Mountain Power Pool. The interconnection of western systems was furthered substantially when the large capacity, extra high voltage interties with the Pacific Southwest were completed. Of these interties, two are of 500 kilovolt alternating current and a third is an 800 kilovolt direct-current line.

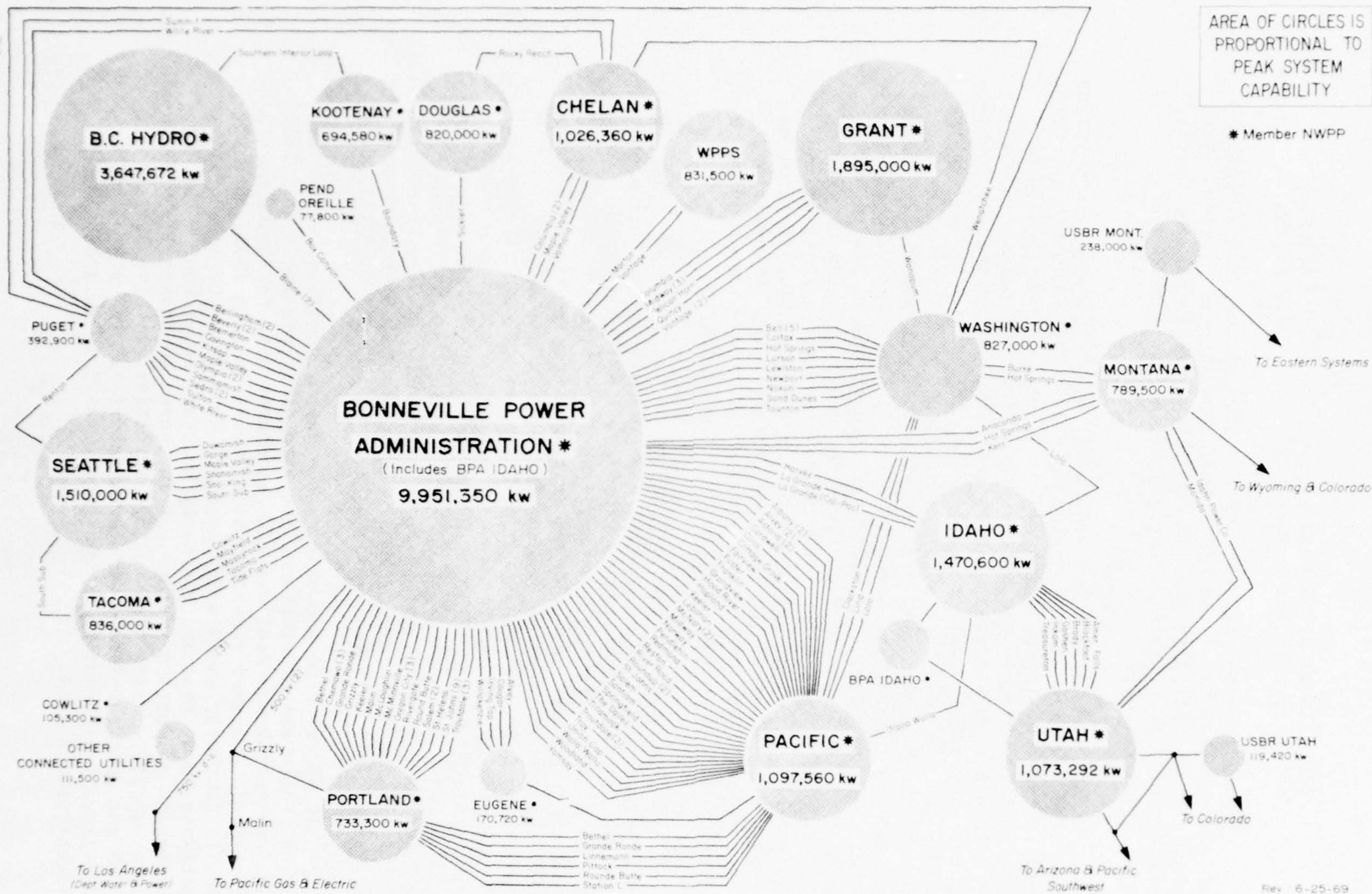
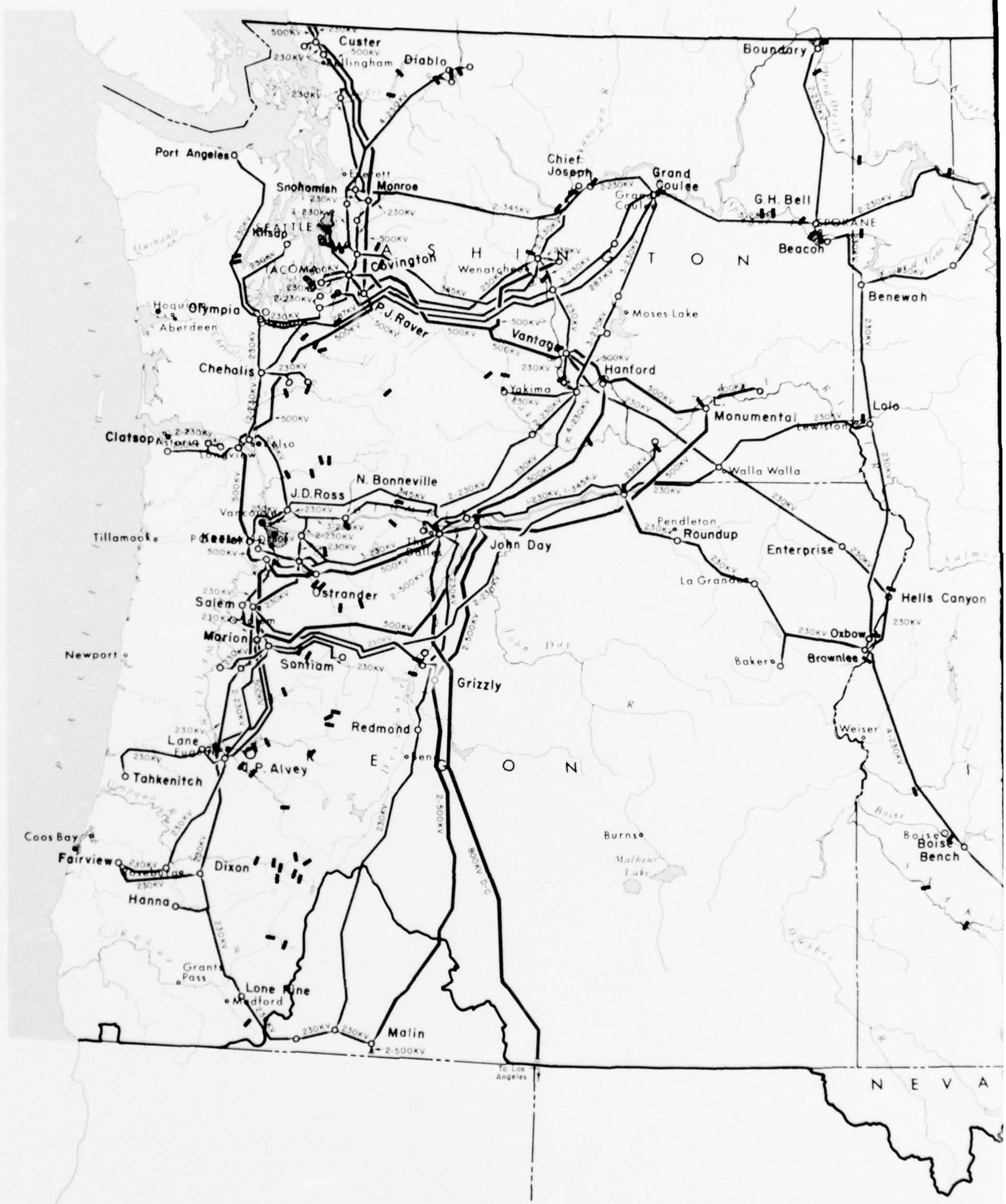


FIGURE 3. Northwest Power Pool Interconnections as of December 31, 1969



Custer
Diablo
Boundary
Port Angeles
Snohomish
Monroe
Chief Joseph
Grand Coulee
G.H. Bell
Beacon
SEATTLE
Kitsap
TACOMA
Covington
Wenatchee
Olympia
Aberdeen
Benewah
P.J. Raver
Moses Lake
Vantage
Hanford
Chehalis
Yakima
L. Monumental
Lolo
Lewiston
Clatsop
Walla Walla
N. Bonneville
J.D. Ross
Pendleton
Roundup
Tillamook
Keeler
John Day
Enterprise
La Grande
Hells Canyon
Salem
Ostrander
Marion
Oxbow
Newport
Santiam
Brownlee
Baker
Grizzly
Redmond
Weiser
Lane
Tahkenitch
Burns
Coos Bay
Boise Bench
Fairview
Dixon
Hanna
Grants Pass
Lone Pine
Medford
Malin
To Los Angeles
N E V A

COLUMBIA - NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

MAJOR TRANSMISSION FACILITIES – 1970

THE REGION
1970

FIGURE 4

The lines permit sales of surplus Northwest secondary energy and peaking capacity to the Southwest. Exchange of capacity between the two regions to take advantage of seasonal differences in load will provide substantial advantages to both regions. The exchange of Pacific Northwest capacity for Pacific Southwest energy will effect savings in capital cost for the Southwest utilities and increase the firm power available in the Northwest. Off peak steam energy from the Southwest will enable the Northwest to firm up some 330,000 kilowatts of secondary energy. The lines also make it possible for the utilities which have purchased Canada's share of the treaty power to sell this power in the Southwest subject to recall as needed in the Northwest.

COORDINATED SYSTEM OPERATION

Coordinated system operation had its beginnings in the early transmission interconnections between utilities. These provided the physical opportunity for voluntary coordination through a power pool. Such voluntary coordination culminated in 1964 in three accomplishments which greatly expanded the scope of power operations and will vastly affect the flow regimen of the Columbia River. The three were (1) ratification of the Columbia River Treaty by Canada, (2) authorization of the Pacific Northwest-Pacific Southwest high voltage transmission interconnections, and (3) the Pacific Northwest Coordination Agreement. These actions should not be viewed in isolation but are in fact closely interdependent. The time schedule for completion of each was geared to the accomplishments expected of the other two.

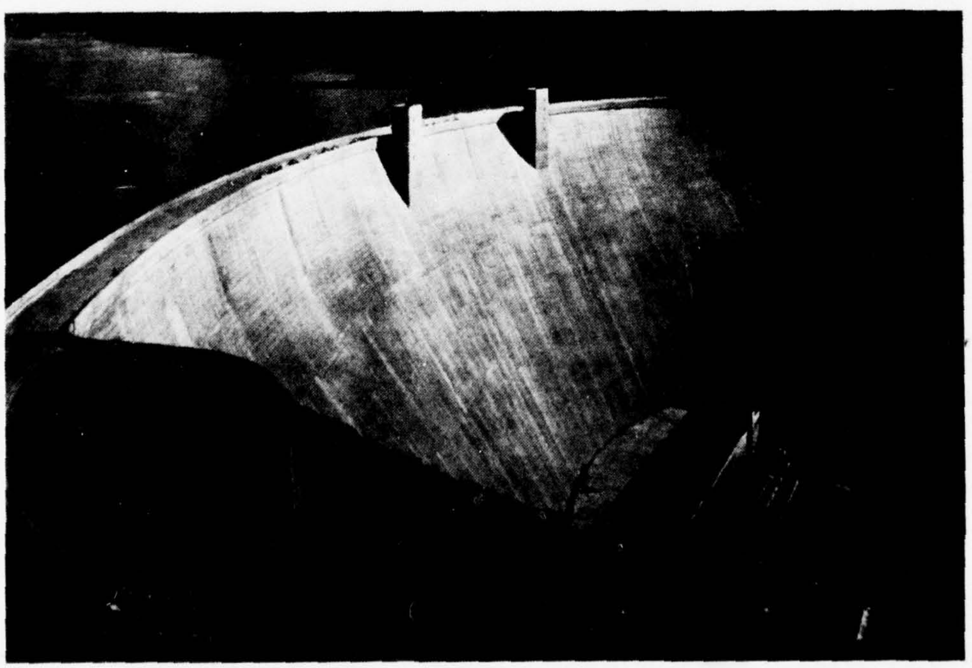
The Northwest Power Pool

The Northwest Power Pool was formed during World War II as a result of an order by the War Production Board for interutility cooperation to increase power generation for industrial production. This operation proved so successful that it has been expanded to include virtually all of the major generating utilities in the Columbia-North Pacific Region and British Columbia. There were beginnings of pooled operation in the Northwest considerably before that time, however. In 1923, the Seattle and Tacoma municipal systems were linked together, as were The Washington Water Power Company and The Montana Power Company. Further interconnections were made through the years so that by the time the War Production Board order was issued, a fairly effective regional transmission system was in existence. The construction of the Federal grid by the Bonneville Power Administration further strengthened the system.

The Power Pool is a voluntary organization whereby the generating facilities of the members are operated together in a

coordinated manner so that the regional load can be met most efficiently. Operating programs are prepared annually on the basis of the utilities' forecasted loads and available resources. In 1964, to conform to the requirements of the Canadian Treaty, many of the coordinated operating procedures of the Power Pool were formalized as a part of the Pacific Northwest Coordination Agreement, which is discussed in detail later. Although not all members of the Power Pool are signatory to the Coordination Agreement, the terms of the agreement must be fulfilled by the Power Pool in preparing its annual operating program. In fact, the same load and resource data and system analysis serve as the basis of both the Power Pool and Coordination Agreement operating programs.

The actual day-to-day operations of the Pool are carried out by agreements and understandings between the respective power dispatchers, power scheduling, and other operating personnel. As an adjunct to the operating program activities, the Pool performs certain other mutually beneficial functions. Examples are the emergency load dropping program, coordination of maintenance outages, various types of testing programs, and an annual review of operations.

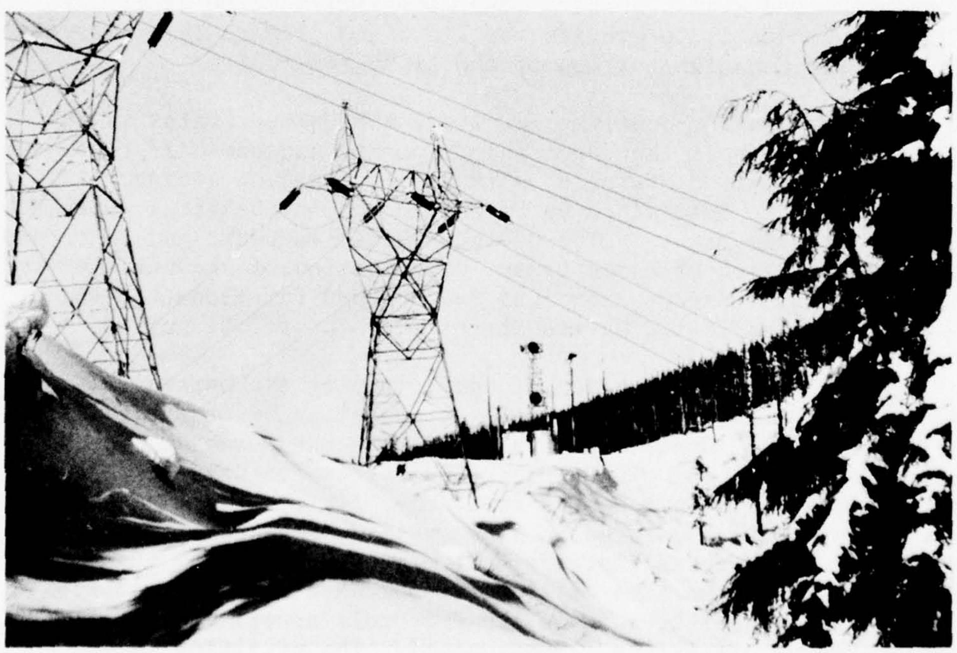


Hungry Horse Dam provides storage usable by 20 hydroelectric plants at site and downstream (Bureau of Reclamation).

Western Systems Coordinating Council

Work of the Western Systems Coordinating Council began in the fall months of 1967. Membership of the council consists of 38 systems with large capacity generating facilities and transmission circuits that serve 36 million people having an electric power demand in 1969 of approximately 49 million kilowatts. The council members cover all or part of 13 western states and British Columbia with high voltage transmission loops extending 2,700 miles around the perimeter of the area.

A primary function of the council is to provide to each member a source of additional generating reserve capacity from neighboring systems. Greater use of the more efficient generating facilities is provided. Greater flexibility is achieved in programming maintenance work. Coordinated scheduling of future generating facilities permits the enhanced economies of larger generating units. These benefits collectively result in reduced capital and operating costs.



Interconnection of the Federal system with other utilities set the stage for eventual coordinated operation (Bonneville Power Administration).

Work of the council is achieved through an Executive Committee, plus committees on Operations, Planning Coordination, Environment, and Public Information. The council maintains liaison with the Western Conference of Public Service Commissions and through its operating committee with the Mid Continent Area Reliability Coordination Agreement (MARCA) on operation of the east-west transmission interconnection.

Columbia River Treaty

Following a long series of negotiations, the Columbia River Treaty was entered into by Canada and the United States in January 1961. The final step in implementation of the treaty occurred on October 1, 1964, with the payment to Canada of $254 million for its share of the downstream benefits resulting from construction of the treaty reservoirs. In late August of that year, the Coordination Agreement was signed about the same time that Congress was acting on the Pacific Southwest interconnection. The treaty provides for Canada to build three reservoirs; Duncan, Arrow Lakes, and Mica, with a total storage of 15.5 million acre-feet usable for improving streamflow in the United States. Construction of these projects is to be completed within 9 years after the ratification date. In addition, Canada is to provide the lands and prepare the reservoir site for the Canadian portion of the Libby reservoir.

In return for benefits received, the United States is to give Canada one-half the dependable capacity and one-half the energy gained in the United States as a result of Canadian storage. The benefit is to be determined by "first added" computations which are described in the treaty. The United States, in addition, is to pay Canada at the time of commencement of operation of each of the three reservoir amounts totaling $64,400,000 for flood control benefits derived in the United States over the treaty period.

Following ratification of the treaty by the United States, changing conditions in Canada made ratification by Canada increasingly difficult. Other new capability made the power surplus to the needs of British Columbia and suggestions for sale outside the Province had not been received favorably. In the end, however, arrangements were completed in January 1964, for operational assurances, assurances that the United States would use its best efforts to raise the $254 million for purchase of the Canadian share of the benefits, and for the Protocols necessary to clarify certain treaty provisions. Subsequently, the utilities in the Northwest and the Federal agencies directly concerned with power worked continuously to complete all interrelated agreements necessary to effect sale of the entitlement by October 1, 1964. The sale extends through the year 2002 to 2003, when the last power benefits under the treaty accrue.

As shown on table 16, Arrow and Duncan reservoirs constructed under the treaty presently provide 8,556,000 acre-feet of storage usable for power generation. When Mica Reservoir is completed, the three treaty reservoirs will provide 20,500,000 acre-feet of active storage. Of this storage, 15,500,000 acre-feet are provided by the treaty for power use in the United States. Mica reservoir is scheduled for initial operation in April 1973. The treaty permits, in addition, the completion of Libby project in the United States, with active capacity of 4,965,000 acre-feet on condition that the reservoir be available for filling in the spring of 1972.

Pacific Northwest-Pacific Southwest Intertie

As the power purchased from Canada will be surplus to needs of the Pacific Northwest in early years, the transmission interconnection with the Pacific Southwest became of increased importance. As a culmination of years of study, proposals, and counter proposals, a recommendation for four high voltage lines to the Southwest was presented to Congress by the Secretary of the Interior on June 24, 1964. Further negotiations led to minor amendments of July 21 and July 27, 1964, and to the final plan. Congress put its final stamp of approval on the plan August 14, 1964, and appropriated funds to begin Federal portions of the lines. As feasibility of the last of the four scheduled lines was incremental to that for the preceding three, feasibility was tested by a favorable report furnished Congress on October 7, 1964. Because of indefinite date of completion of the fourth line, subsequent definite scheduling of thermal generating plants in the Pacific Southwest preempted some of the contemplated benefits. As a consequence utilities of the Southwest announced on March 14, 1969, their intention to delay firm use of the line until after 1977. Plans for completing this specific line were, therefore, shelved.

Pacific Northwest Coordination Agreement

The third of the interrelated accomplishments in 1964, which control operation of the Columbia River's hydroelectric development, is the Pacific Northwest Coordination Agreement. The agreement is a contract for planned operation among the major power generating utilities of the region. It became effective on January 4, 1965, and is to terminate on June 30, 2003. The agreement is among 16 parties controlling power generating facilities in an area which approximates the Columbia-North Pacific study area.

The generating capacity of the parties as summarized on table 18 is 20,203,000 kilowatts at 109 hydroelectric plants and 400,000 kilowatts at 14 thermal-electric plants. As defined by

the contract the firm energy load which the coordinated system is able to carry in 1970-71 is 11,611,100 average kilowatts.

There are 22,485,000 acre-feet of reservoir storage owned by the parties and dedicated to coordination use subject to the owning parties' primary use as limited by the agreement.

Table 18 - Pacific Northwest Coordination Agreement
Estimated Capability of Signatory Parties, 1970-71

Party	Hydroelectric Plants		Thermal-electric Plants	
	Number	Peaking Capacity Megawatts 2/	Number	Peaking Capacity Megawatts
United States 1/	26	10,900	1 3/	0 3/
City of Eugene	4	137	1	34
City of Seattle	6	1,462	2	62
City of Tacoma	6	769	2	65
Grant County PUD	2	1,895	0	0
Chelan County PUD	3	1,026	0	0
Pend Oreille County PUD	1	77	0	0
Douglas County PUD	1	820	0	0
Cowlitz County PUD	0	0	0	0
Puget Sound Power & Light Co.	6	310	2	89
Portland General Electric Co.	8	661	1	72
Pacific Power & Light Co.	34 4/	1,090 4/	5	78
The Washington Water Power Co.	10	831	0	0
The Montana Power Co.	2	225	0	0
Colockum Transmission Co.	0	0	0	0
Total	109	20,203	14	400

1/ Includes the Federal Government and the United States Entity with Southern Idaho plants and Packwood Lake.
2/ At full reservoir levels estimated January 1971.
3/ New Production Reactor available to the United States by contract--currently not credited with firm peaking capacity.
4/ Includes Swift No. 2 of Cowlitz County PUD and plants in Klamath River Basin.

Although the final impetus to the coordination agreement stems from the Canadian Treaty and the transmission interconnection with the Southwest, the basic causes for its completion lie much further in the past. The history of all these would be tedious, but a few of the more important causes can be listed as follows:

1. Informal noncontractual planning for operation through the Northwest Power Pool established a useful pattern of cooperation among the utilities.

2. Construction of the Federal transmission grid provided a vital physical means for interchange of power among utilities.

3. Although the ownership of storage reservoirs rested with diverse utilities, the collective operation of these reservoirs determined the firm load which the powerplants of the region could carry.

4. The interutility flow of storage benefits is recognized by Section 10(f) of the Federal Power Act which requires interutility payments, with important exceptions, for storage benefits.

5. With increased reservoir storage the interconnected systems face a critical storage release period extending beyond a single year which intensifies the need for interutility planned operation.

6. When interconnected, utilities have a reduced total requirement for generator reserves.

A fundamental concept of the Coordination Agreement is "Firm Load Carrying Capability" commonly abbreviated FLCC. For the coordinated system of all 16 parties, the FLCC is the aggregate firm load that the system could carry under coordinated operation under critical period streamflow conditions and with use of all reservoir storage. Critical period has reference to the streamflow period over which, if all energy generation is fitted to load, there would be a minimum capability to carry firm load. During all other periods there would be an additional margin of capability, or energy would be retained in reservoirs from which such additional margin could be generated.

In order to accomplish such coordinated operation, the combined power facilities of the parties are operated to produce optimum ability to carry firm load. Each party is entitled to a FLCC equal to its capability in the critical streamflow period of the coordinated system with full upstream storage release, with two exceptions. The exceptions are the reimbursement of treaty benefits to Canada and restoration of capability to parties which suffer loss in critical period capability as a result of the change in critical period capability brought about by treaty storage. Firm load carrying capabilities are sustained by the interchange of energy between parties.

Prior to the start of a contract year, a schedule of critical period reservoir operation is set up to provide optimum FLCC to the coordinated system. From the same operation an energy content curve is derived for each reservoir. This curve represents a schedule of levels that the reservoir should follow in order to assure FLCC for the coordinated system, although adjustments are provided to reflect improved forecasted streamflows as the season advances. If, as may frequently happen, the system requires a planned cut back on releases in order to hold storage for later use, thereby reducing the generation of the storage owner and other downstream owners below FLCC, these owners have the right to receive interchange energy from a party with excess capability. Subsequently, when the cut-back storage is scheduled for release, the interchange energy will be returned on request of the supplying party.

Provision is made for payments for any imbalances in interchange energy accounts at the end of a contract year.

Under the agreement a downstream owner is entitled upon request to energy which he could generate at his plants if upstream reservoirs released all water above energy content curves. At his option the upstream owner can deliver energy "in lieu" of such water if he has surplus energy and the storage should be conserved for later use.

The agreement also provides for the storage of surplus energy of one party in available reservoir space belonging to a second party. The original owner of the energy pays a storage charge upon the return of such energy.

The agreement makes interconnecting transmission facilities available for coordination use subject to the owners' prior requirements. Equitable charges are provided for capacity, energy, transmission, and other services in addition to the charges for interchange and storage.

A formula is provided in the agreement for determination of that part of reservoir costs which will be paid by downstream beneficiaries, based on the improvement in these beneficiaries' FLCC through operation of the storage. The contract expresses the intent that these payments discharge the obligation for payments under Section 10(f) of the Federal Power Act.

The agreement also provides for the determination of reserve capacity requirements and includes provisions safeguarding nonpower uses of the water, including irrigation, flood control, and releases for fish life. Prior contracts, water rights, Federal reclamation projects, and the rights of public bodies to preference power are also protected.

THE HYDRO-THERMAL PROGRAM

To the present time, load growth in the region has been met by the construction of new hydroelectric plants. Considerable feasible hydroelectric capability remains for development, as is discussed subsequently herein, but this cannot be developed at a rate which meets the load growth of the region which in the 10 years through 1965 averaged two billion kilowatt-hours per year. The load is expected to triple in the next 20 years. A demand of this magnitude is most economically met by large scale thermal electric plants integrated with hydroelectric peaking facilities.

To meet the challenge of new power supply, the Joint Power Planning Council, which is made up of representatives from the

utilities in the Pacific Northwest, has established a plan projecting the development of about 20 million kilowatts of hydro peaking capacity and 21.4 million kilowatts of thermal-electric capacity by 1990. The plan, selected from the various alternatives which were studied, has the following features:

1. Non-Federal utilities will build thermal plants, located, sized, and scheduled to best satisfy regional needs.

2. Maximum sized thermal plants will provide limited surplus power which will be acquired by BPA on a short term withdrawable basis from private utilities' share of power under exchange arrangements.

3. Public agencies' share of thermal plant capability will be acquired by BPA under a net billing arrangement. That is, each public agency's share of thermal plant cost will be offset against amounts owed BPA by that customer under all his obligations to BPA.

4. The acquired thermal power will be pooled with existing Federal hydropower and the integrated product will be furnished BPA customers at established rates.

5. Peaking power, high voltage transmission, and forced outage generator reserves will be provided private utility thermal plants from the Federal system.

6. Regional reserves for unanticipated load growth will be provided by the Federal system.

The proposed hydro-thermal program appears to be the most practicable method for providing an integrated power supply for the region. Without the necessity of additional legal authorization, it would provide a further source of power for the load growth of preference customers. It would allow the utilities, both those publicly and privately owned, to construct the largest and most economical thermal generating plants, provide minimum cost bulk transmission for both hydro and thermal power, and provide a power supply for the growth of electroprocess industries. It would enhance use of the Federal investment in hydroelectric and transmission facilities and would stimulate continued economic growth of the region. The additional investment in electrical facilities including generation, transmission, and distribution will approximate 16 billion by 1990. Approximately two-thirds of this investment will be by non-Federal entities and about one-third by the Federal Government.

FUTURE ELECTRIC POWER REQUIREMENTS

UNITED STATES REQUIREMENTS

Electric power signifies convenience, growth, dynamism. Industrial growth during past years has been consistent and high, almost 7 percent annually. The prospect for a continuation of steady expansion in future years seems good, and the estimates are made assuming such a continuation. They are predicated on a conclusion to the war in Vietnam coupled with a companion assumption that the economy will shift to other avenues of growth without any sizable setback because of a contraction in military spending. No attempt is made to forecast cyclical variations in the demand for electric power even though such oscillations have taken place in former years and are certain to happen in the future.

Increases expected in the various categories of electric energy use are discussed in the paragraphs following.

Domestic energy use in 1966 amounted to 299 billion kilowatt-hours with an average use per customer of 5,200 kilowatt-hours. Continued growth in sales and use of all types of appliances, particularly high-energy requirement devices such as electric ranges, water heaters, and space heating and cooling equipment, is expected to build annual residential energy requirements to 16,900 kilowatt-hours per customer, totaling 1,417 billion kilowatt-hours by 1990.

Electric energy needs of commercial users (restaurants, hotels, shops, etc.) which in 1966 totaled some 209 billion kilowatt-hours are also growing even faster than our exploding population. While not as great in magnitude as residential usage, commercial requirements will increase at a higher rate and will total 1,142 billion kilowatt-hours in 1990.

Industrial production of the country should continue its upward climb. "With an optimistic and growing population, there is good reason to believe the forecasts that by 1980 our output will be four-fifths larger than at present."(4) Production increases coupled with the ever-expanding use of electric power in industry form the basis for the projected industrial energy use in 1990 of 2,393 billion kilowatt-hours.

Future electric energy requirements classified as "Other," i.e., miscellaneous uses including street lighting, electrified

transportation, etc., are estimated to increase at a rate roughly paralleling the growth in the other classifications reaching 264 billion kilowatt-hours in 1990.

Table 19 summarizes projected energy requirements of the Nation by classification at 10-year intervals, 1970-1990, inclusive.

Table 19 - Projected Electric Energy Requirements of the United States by Classification

Classification	1970	1980	1990
	(billion kilowatt-hours)		
Farm, including Irrigation and Drainage Pumping	52	83	132
Nonfarm Domestic	381	759	1,417
Commercial	279	579	1,142
Industrial	616	1,260	2,393
Other	66	136	264
Ultimate Consumer - Total	1,394	2,817	5,348
Losses	135	269	504
Energy for Load - Total	1,529	3,086	5,852

PACIFIC NORTHWEST REQUIREMENTS

Regional annual energy requirements will increase from 74,435 million kilowatt-hours in 1965 to 1,096 million megawatt-hours by 2020. This represents an overall 55-year compound annual rate of growth of 5.0 percent.

Basic Assumptions

Basic assumptions for estimate of regional power requirements are as follows:

Population will grow from 5.9 million in 1965 to 7.3 million by 1980 in the Columbia-North Pacific Region. By 2020 the population will be 12.7 million. During the 1965-2020 period, the compound annual rate of growth will be 1.4 percent.

Employment opportunities through industrial diversification will supplement the present natural resource based industries in agriculture, forest products, and mining. Regional growth will assure an expansion and greater employment opportunities in the service industries.

The regional wholesale electric power costs will continue at lower than national average costs as an inducement to industrial

growth. Future power will be generated, in part, from higher cost steam turbine generators. Both fossil fuel fired plants and nuclear powerplants will contribute to the regional power supply. The blending of hydroelectric power with steam generation will result in a continuing lower local average wholesale power cost compared with the national average.

Energy Loads by Consumer Classifications

The projected power requirements reflect a steady growth in sales to all major consumer classifications.

Domestic

Ratios between population estimates and domestic customers have been developed to 1980 based on historical trends. Average annual use per domestic customer will grow from 9,465 kilowatt-hours in 1960, to 17,700 kilowatt-hours by 1980, based on the major appliance saturation estimated in table 20.

Table 20 - Estimated Contribution of Selected Appliances to Total Domestic Average Use

Appliance	Percent Saturation	Appliance Avg. Annual KWH Use	Contribution to Total Avg. Use-KWH
1960			
Electric Heat	12	11,000	1,320
Water Heater	81	4,500	3,645
Range	83	1,400	1,162
Automatic Laundry	51	1,000	510
Freezers	29	900	261
Air Conditioners	5	1,500	75
All Others 1/			2,492
Total Use			9,465
1980			
Electric Heat	45	12,000	5,400
Water Heater	86	5,500	4,730
Range	88	1,400	1,232
Automatic Laundry	75	1,000	750
Freezers	30	1,600	480
Air Conditioners	20	1,500	300
All Others 1/			4,808
Total Use			17,700

1/ Radio, television, electric blankets, blenders, coffeemakers, dishwashers, frypans, irons, mixers, toasters, vacuum cleaners, etc.

By 1980 approximately 26 percent of regional energy sales will be to domestic consumers. From past experience, the forecast domestic consumption could be conservative. The introduction of new appliances and consumer acceptance of electric space heating could mean that the 1980 estimate might be realized earlier.

Commercial

Ratios between estimated population and number of commercial customers have been developed to 1980 based on historical trends. Average annual use per commercial customers will grow from 36,607 kilowatt-hours in 1965 to approximately 67,200 kilowatt-hours by 1980.

Commercial customers will require more electricity to satisfy greater demands for improved lighting, electric heating, and air conditioning, as already evidenced in the newer shopping centers. Records for the number of commercial establishments now having electric heat installations are not available but evidence of a widespread and growing use exists. Competition will force modernization of existing commercial establishments. By 1980, approximately 13 percent of regional energy sales will be for commercial use.

Industrial

No ratios between population and industrial customers were developed. There is little reliability on the number developed and no assurance on the size of the industrial plants.

Average energy use per industrial customer is of dubious value in forecasting due to wide variation in consumption among individual customers. Instead, the total demand for this category was developed based on potential growth of industries likely to expand or initially operate in the area. Industrial sales will represent 56 percent of the total regional energy sales by 1980. This is slightly higher than the national total due to electric-process industries locating in the Pacific Northwest. Greater energy input per unit of product in the forest products industries and pulp and paper manufacturing is forecast. Higher metal prices and extensive mineral reserves will sustain continued mining and refining. Manufacturing in the aerospace industries will continue at a high level. The regional advantage of available lower cost power will attract more of the aluminum and other electroprocess industries. Other electroprocess industries forecast for the area include magnesium and titanium production.

Irrigation

As additional lands are brought under irrigation, power loads will increase substantially for this purpose. During 1966, 7.3 million acres were irrigated in the region, of which 1.8 million were sprinkler irrigated. By 1980, 10.1 million acres will be required to meet future needs, of which 4.7 million will be sprinkler irrigated. Much of the new land is at higher elevations, requiring greater pumping loads. By 1980, approximately 4 percent of regional energy sales will be for irrigation use.

Street and Highway Lighting

Growth can be expected in street and highway lighting. More existing avenues will have street lighting installations to improve community safety. New highways will require greater illumination. Approximately one percent of total sales were in this category in 1965. Forecast 1980 sales will be double this level but will still represent one percent of total sales.

Losses and Annual Load Factors

Transmission losses as a percent of total power generated for the public supply were 10 percent during 1965. By 1980, energy losses will double but will be approximately 9 percent of the total power generated. The decline in loss ratio is consistent with the utility industry experience both nationally and locally. The change in loss ratios in the area will be due, in part, to the greater use of higher voltage lines during the 1970's. As more of the higher voltage lines are used, the loss ratios will decline. In time, as load growth absorbs the extra capacity of these lines, there will be a tendency for loss ratios to increase. Another factor will be the location of new steam electric plants closer to load centers requiring shorter transmission distances.

The average of the annual load factors during the 1955-65 period was 66.7 percent with a standard deviation of 2.7 percent in the Pacific Northwest area. That is, two-thirds of the time the annual load factors were within the range of 64.0 through 69.4 percent. A least squares trend line for the period indicates a declining load factor in the area. This is contrary to the national experience in recent years where the annual load factor has been increasing. In a limited sample, one or two unusual occurrences can substantially influence the trend line. During the 1955-65 period the unusually cold December occurred late in the period and the unusually mild December occurred earlier. Had these instances been reversed, the trend would not be as pronounced. Adjusting these 2 years to near normal conditions, there is still a slight decline noticeable.

Aside from historical evidence as an aid in determining future annual load factors, consideration of the composition of future electric loads gives some justification for a near static or slightly declining trend in annual load factors in the area through the year 2020. Extensive electric space heating is anticipated; but extensive summer air conditioning to offset this lower load factor seasonal service is not. However, utility promotion of more air-conditioning sales may be expected. Irrigation loads will be greater. The high load factor electroprocess industry served in the area substantially influences the annual load factor. During 1965, approximately one-fifth of the area energy load comprised this class of service. By 2020, with the growth of sales to other classes of service the ratio of electroprocess industry load to the total will decrease. This can cause the annual load factor to decline. The conclusion made for this forecast is that annual load factors decline from 65 percent in 1965 to 64 percent by 1980. This same annual load factor was used for the subsequent period through 2020.

Total Annual and Monthly Loads

Estimates of power requirements for the years 2000 and 2020 have not been developed in detail. Growth rates paralleling the Pacific Northwest area forecast used by the Pacific Northwest Utilities Conference Committee (20) were used as guidelines in the extension to the year 2020. Regional loads for the years 1965, 1980, 2000, and 2020 are shown in table 22.

For comparative purposes, selected annual rates of growth in electric power requirements for the Pacific Northwest are as follows in percent for designated periods.

Actual--	
1955-1965	5.6
1960-1965	6.5
Forecast--	
1965-1980	6.5
1980-2000	4.7
2000-2020	4.2
1965-2020	5.0

Regional monthly peak and energy load patterns were constructed by using the index shown in table 21. This index is based on the monthly load patterns developed by the utilities in the area and used in a recent Pacific Northwest Utilities Conference Committee report (4). The index was used for the years 1980, 2000, and 2020 in table 23 to show regional monthly peak and energy requirements.

Table 21 - Monthly Index of Load, Columbia-North Pacific Region

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
						(percent of annual)						
Peak	96.1	90.7	87.4	84.7	82.4	79.6	79.7	80.9	83.2	87.4	95.6	100.0
Average	9.3	8.0	8.5	8.0	7.9	6.6	8.0	8.1	7.9	8.4	8.7	9.6

Table 22 - Future Electric Power Requirements, Columbia-North Pacific Region

	1965	1980	2000	2020
Population (Millions)	5.9	7.3	9.7	12.7
Ratio: Pop./Dom. Cust.	3.1/1	2.8/1		
Domestic Customers	1,878,814	2,607,000		
KWH Use per Dom. Cust.	11,011	17,700		
Total Domestic Use GWH	20,687	46,144		
Ratio: Pop./Com. Cust.	24.5/1	22.5/1		
Commercial Customers	239,883	325,000		
KWH Use per Com. Cust.	36,607	67,200		
Total Com. Cust.	8,781	21,840		
Industrial Customers	6,486	-		
Industrial KWH Use per Capita	5,936	-		
Total Industrial Use GWH	34,346	99,000		
Irrigation GWH	2,421	6,593		
Other GWH	1,090	2,259		
Total Sales GWH	67,325	175,836		
Losses	7,110	17,364		
Total Requirements GWH	74,435	193,200	479,000	1,096,000
Per Capita KWH Requirements	12,676	26,500	49,400	86,300
Peak-megawatts	13,068	34,400	84,800	191,700
Average-megawatts	8,497	22,000	54,660	125,060
Load factor-percent	65.0	64.0	64.4	65.0

Electric power estimates for the region with alternate higher population projections in the Puget Sound and Willamette subregions would be as follows:

	2000	2020
Total Requirements Million kwh	512,000	1,286,000
Peak-megawatts	91,300	229,400

Table 23 - Monthly Load Patterns, Columbia-North Pacific Region

Month	1980		2000		2020	
	Peak	Energy	Peak	Energy	Peak	Energy
	(In millions of kilowatt hours of Energy and thousands of kilowatts of Peak)					
January	33,100	17,900	81,500	44,300	184,200	101,500
February	31,200	15,500	76,900	38,500	173,900	88,100
March	30,100	16,500	74,100	41,100	167,500	94,000
April	29,100	15,400	71,800	37,900	162,400	86,700
May	28,300	15,300	69,800	38,200	157,900	87,400
June	27,400	14,700	67,500	36,600	152,600	83,300
July	27,400	15,500	67,600	38,200	152,700	87,500
August	27,800	15,600	68,600	38,600	155,100	88,400
September	28,600	15,200	70,600	37,600	159,500	86,000
October	30,100	16,300	74,100	40,400	167,500	92,300
November	32,900	16,800	81,800	41,700	183,200	95,600
December	34,400	18,500	84,800	45,900	191,700	105,200
Annual	34,400	193,200	84,800	479,000	191,700	1,096,000

Electric power estimates for the region with alternate higher population projections in the Puget Sound and Willamette subregions would be as follows:

	2000		2020	
	Peak	Energy	Peak	Energy
Annual	91,300	512,000	229,400	1,286,000

There are other Pacific Northwest area load forecasts. These differ because of designated service areas or date of preparation. The Pacific Northwest Utilities Conference Committee West Group Forecast (PNUCC) report prepared jointly by major utilities with generation in the region has been a basic planning document and is revised annually. The Columbia-North Pacific Region service area is larger than the PNUCC area because all of Idaho and Western Montana and minor parts of Nevada and Wyoming are included. However, loads used in the Columbia-North Pacific Region report are comparable with the PNUCC (1968) report when appropriate adjustments are made. Federal Power Commission forecasts follow designated "Power Supply Areas" and do not coincide with either of the above designated areas. For longer range planning purposes one load forecast is generally used rather than a "high" and "low" range. Because of substantial differences in population forecasts for two of the subregions, prepared by different planning groups, this report departs from this procedure and shows two load levels for the years 2000 and 2020.

The Columbia-North Pacific report used population projections prepared by the Office of Business Economics of the U. S. Department of Commerce. Higher population projections were proposed by Regional Economic Studies Technical Committees for the Puget and Willamette Basin investigations.

FUTURE ELECTRIC POWER RESOURCES DEVELOPMENT

The growth in electric power requirements in the region will result in a large sustained investment in power generating facilities. The requirement of 512 billion kilowatt-hours by 2000 is approximately equal to the power requirements of the entire United States in 1955, shown by table 2. The new generation to meet this load growth by 2000 exceeds the installed generation of any country in the world except the United States or the Soviet Union. The significance of this growth to basin planning lies in the impact of hydroelectric plants on river development and in the large water requirements for cooling thermal generating plants.

ELECTRIC POWER RESOURCES

At present the region's power requirements are supplied almost entirely from hydro generation. Most of the economically feasible hydro energy in the region is provided by the hydroelectric plants existing and under construction. The remaining unconstructed hydro projects are of smaller size and cannot be completed at a rate sufficient to meet the growth of energy load. Opportunities remain for construction of hydro peaking capability somewhat further into the future. The load which the hydroelectric resources are unable to meet will be supplied by thermal electric generation. In keeping with the past pattern of cooperation in the region, and for maximum economy, these thermal plants will be provided by cooperative investment by both public and private utilities.

Hydroelectric Resources

In the past, the main source of electric energy in the Pacific Northwest has been its hydroelectric resources. The rapidly growing population and expanding economy have accelerated hydroelectric development to the extent that a substantial part of the region's economical hydro sites will soon be developed, and the region will have to turn to thermal-electric sources to serve the bulk of the base energy load growth. Although the number of remaining economical sites decreases as development takes place, the gradual shift to a hydro-thermal system will increase the demand and value of hydro peaking capacity. It may be expected that many projects which formerly proved to be marginal or uneconomical under higher plant factors will be reconsidered as sources for low load factor peaking. In addition, the increasing

demands for additional water resource development projects to satisfy the growing needs for municipal and industrial water, irrigation, water quality, recreation, fish and wildlife, and flood control will provide many opportunities for including hydroelectric power as a project function. Among the major basins where little or no water resource development has been accomplished are the Salmon and Clearwater rivers. Others of lesser magnitude are the John Day, Wenatchee, Snoqualmie, and the Upper Snake River and tributaries. Major undeveloped sites also remain on the Middle Snake, Flathead, Kootenai, and Middle Columbia rivers.

In addition to the construction of new conventional hydroelectric projects, there are a number of other ways by which the hydroelectric resource base of the region can be improved. The value of the existing hydroelectric generation can be increased by modifying the regulation of reservoirs to permit the optimal utilization of both the hydroelectric and thermal generation resources of the region. The way in which this regulation is carried out will gradually change as the proportion of thermal to hydro generation changes. In addition, valuable peaking capacity can be obtained by adding units at existing plants and through the construction of pumped-storage projects.

Inventory of Potential Projects

This section presents an inventory of the identified potential conventional hydroelectric projects located in the river basins cited above. It is emphasized here that the inclusion of any project plan or proposal in this report does not constitute an implied preference and, further, that the omission of any project or proposal does not constitute an implied rejection of those projects. It is recognized that some of the projects listed could have a detrimental effect on fish and wildlife populations. Others may conflict with existing or proposed plans for the use of the site's land and water resources. For these reasons, certain agencies and other organizations have gone on the record as opposing a number of the projects listed in the inventory. It is impossible to identify all of the possible conflicts on a project-by-project basis as in many cases the information is not available. However, the fact that these potential conflicts could exist should be kept in mind and given consideration in plan formulation and detailed project studies.

The project descriptions are arranged by subregion and the sources of data are indicated by reference numbers at the end of the project descriptions. The tabulated data summaries prepared for most of the subregion's list project average annual energy based on 2010 irrigation depletions and maximum plant capability (overload) under ultimate development. This is usually 15 percent greater than

W A S H I N G T O N
O R E G O N
I D A
M O
NEVADA
Bellingham
DIABLO GORGE
ROSS
UPPER BAKER
LOWER BAKER
Everett
SEATTLE
SNOQUALMIE FALLS
CEDAR FALLS
TACOMA
CUSHMAN NO 1
CUSHMAN NO 2
WHITE RIVER
Hoquiam
Aberdeen
Olympia
ELECTRON
YELM
LA GRANDE
ALDER
MOSSYROCK
MAYFIELD
PACKWOOD LAKE
Astoria
Longview
Kelso
SWIFT NO.2, NO.1
YALE
MERWIN
Vancouver
BONNEVILLE
CONDIT
POWERDALE
The Dalles
THE DALLES
JOHN DAY
Tillamook
PORTLAND
SULLIVAN
BULL RUN
RIVER MILL
FARADAY
NORTH FORK
OAK GROVE
TIMOTHY MEADOWS
Salem
Newport
BIG CLIFF
DETROIT
GREEN PETER
FOSTER
PELTON
ROUND BUTTE
CARMEN
TRAIL BRIDGE
LEABURG
WATERVILLE
Eugene
DEXTER
COUGAR
LOOKOUT POINT
Bend
HILLS CREEK
Coos Bay
TOKETEE
SLIDE CREEK
SODA SPRINGS
Roseburg
FISH CREEK
LEMOLO NO.1
LEMOLO NO.2
CLEARWATER NO.1
CLEARWATER NO.2
PROSPECT #1, #2, #4
LOST CREEK
Grants Pass
Medford
GREEN SPRINGS
CHIEF JOSEPH
WELLS
CHELAN
Grand Coulee
GRAND COULEE
ROCKY REACH
Wenatchee
ROCK ISLAND
Moses Lake
WANAPUM
NACHES
ROZA
Yakima
PRIEST RAPIDS
LOWER MONUMENTAL
ICE HARBOR
CHANDLER
MCNARY
Walla Walla
Pendleton
La Grande
Baker
Burns
BOUNDARY
BOX CANYON
ALBENI FALLS
LONG LAKE
NINE MILE
LITTLE FALLS
SPOKANE
MONROE ST
UPPER FALLS
POST FALLS
LOWER GRANITE
LITTLE GOOSE
Lewiston
LEWISTON
DWORSHAK
LIBBY
CABINET GORGE
NOXON RAPIDS
HELLS CANYON
OXBOW
BROWNLEE
Weiser
BLACK CANYON
Boise
BOISE DIVERSION
SWAN FALLS
STRIKE
LOWER SALMON
UPPER SALMON

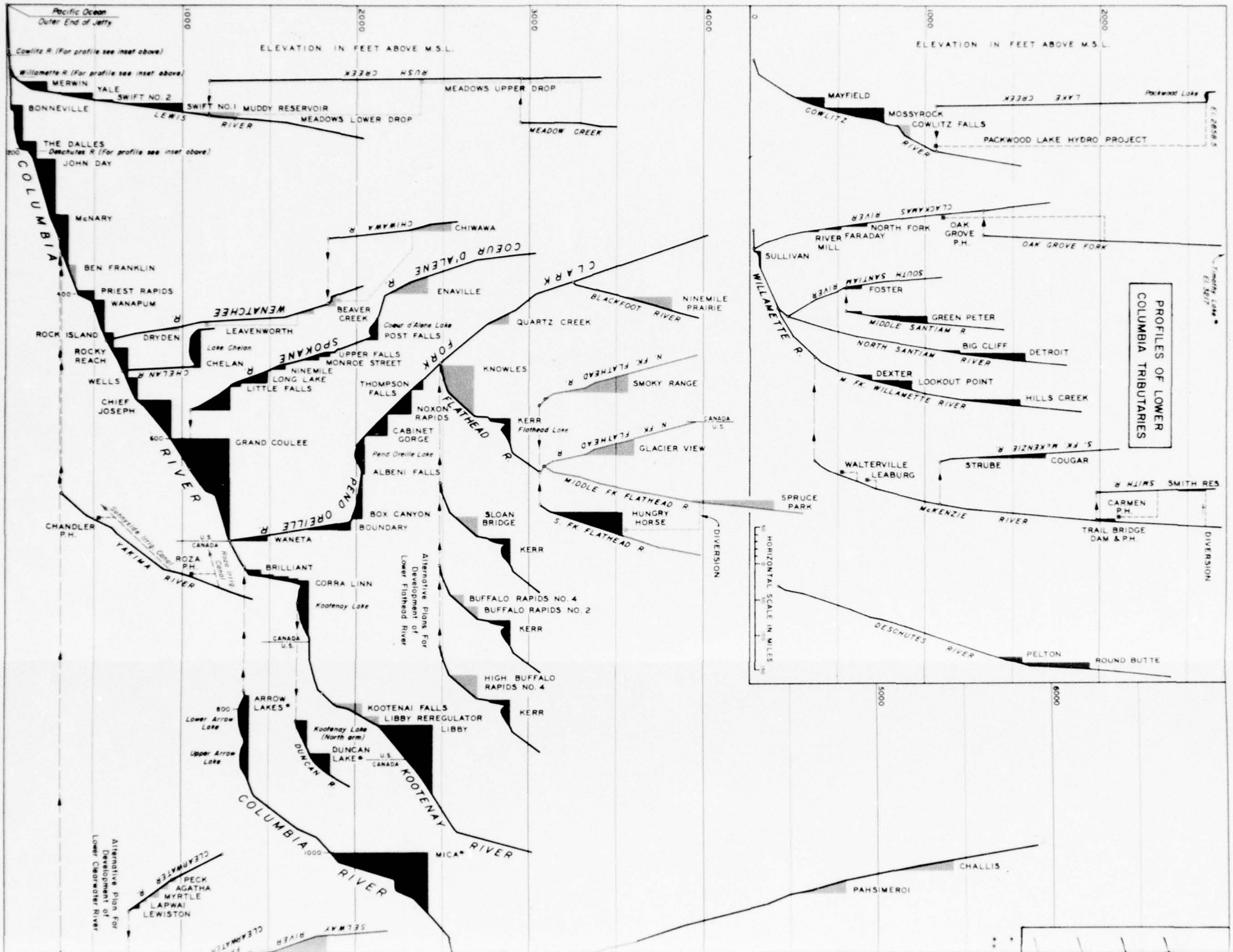
COLUMBIA-NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

HYDROELECTRIC POWER RESOURCES

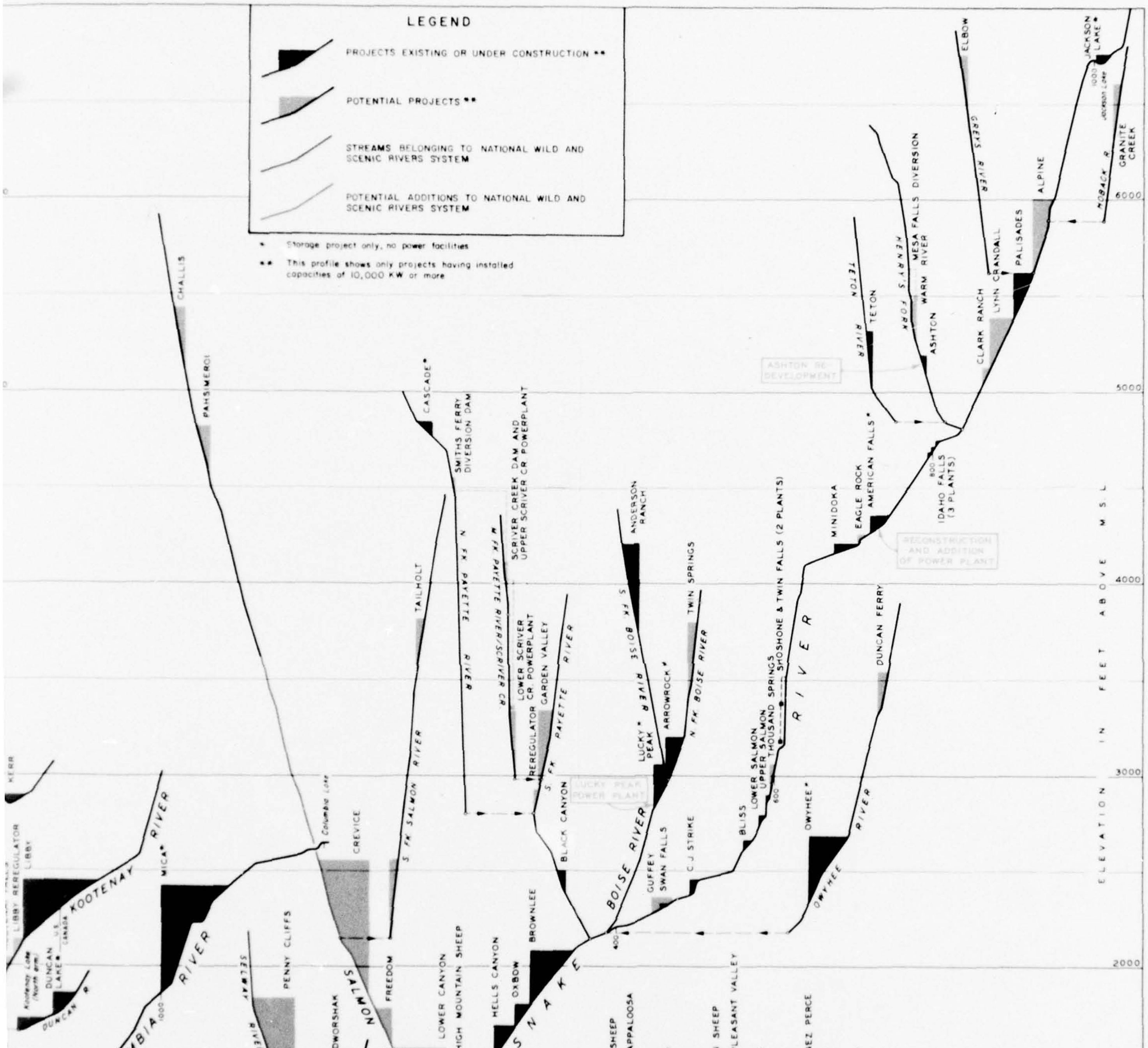
THE REGION

1968

FIGURE 5



PROFILES OF LOWER COLUMBIA TRIBUTARIES
ELEVATION IN FEET ABOVE M.S.L.
HORIZONTAL SCALE IN MILES
Pacific Ocean
Outer End of Jetty
Cowlitz R. (For profile see inset above)
Willamette R. (For profile see inset above)
Deschutes R. (For profile see inset above)
BONNEVILLE
MERWIN
YALE
SWIFT NO. 2
SWIFT NO. 1
MUDDY RESERVOIR
MEADOWS LOWER DROP
MEADOWS UPPER DROP
RUSH CREEK
MEADOW CREEK
LEWIS RIVER
THE DALLES
JOHN DAY
COLUMBIA
McNARY
BEN FRANKLIN
PRIEST RAPIDS
WANAPUM
ROCK ISLAND
ROCKY REACH
WELLS
CHIEF JOSEPH
GRAND COULEE
RIVER
DRYDEN
LEAVENWORTH
WENATCHEE R
CHIWAWA R
CHIWAWA
Lake Chelan
CHELAN
CHELAN R
BEAVER CREEK
COEUR D'ALENE R
ENAVILLE
Coeur d'Alene Lake
POST FALLS
SPOKANE
UPPER FALLS
MONROE STREET
NINEMILE
LONG LAKE
LITTLE FALLS
CLARK FORK
BLACKFOOT RIVER
NINEMILE PRAIRIE
QUARTZ CREEK
KNOWLES
THOMPSON FALLS
NOXON RAPIDS
CABINET GORGE
Pend Oreille Lake
ALBENI FALLS
BOX CANYON
BOUNDARY
PEND OREILLE R
WANETA
FLATHEAD R
KERR
Flathead Lake
N. FK. FLATHEAD R
SMOKY RANGE
GLACIER VIEW
CANADA
U.S.
MIDDLE FK FLATHEAD R
SPRUCE PARK
HUNGRY HORSE
S. FK FLATHEAD R
DIVERSION
Alternative Plans For Development of Lower Flathead River
SLOAN BRIDGE
BUFFALO RAPIDS NO. 4
BUFFALO RAPIDS NO. 2
HIGH BUFFALO RAPIDS NO. 4
CHANDLER P.H.
Sunnyside Irrig. Canal
ROZA P.H.
Roza Irrig. Canal
YAKIMA RIVER
BRILLIANT
CORRA LINN
Kootenay Lake
ARROW LAKES*
Lower Arrow Lake
Upper Arrow Lake
KOOTENAI FALLS
LIBBY REREGULATOR
LIBBY
Kootenay Lake (North arm)
DUNCAN LAKE*
DUNCAN R
KOOTENAY
COLUMBIA RIVER
MICA*
CHALLIS
PAHSIMEROI
Alternative Plan For Development of Lower Clearwater River
CLEARWATER R
PECK
AGATHA
MYRTLE
LAPWAI
LEWISTON
SELWAY RIVER
MAYFIELD
MOSSYROCK
COWLITZ FALLS
COWLITZ RIVER
LAKE CREEK
Packwood Lake
El. 2858.5
PACKWOOD LAKE HYDRO PROJECT
CLACKAMAS RIVER
NORTH FORK
RIVER MILL
FARADAY
OAK GROVE P.H.
OAK GROVE FORK
Timothy Lake
El. 3217
SULLIVAN
WILLAMETTE R.
SOUTH SANTIAM RIVER
FOSTER
GREEN PETER
MIDDLE SANTIAM R
NORTH SANTIAM RIVER
BIG CLIFF
DETROIT
DEXTER
LOOKOUT POINT
M. FK. WILLAMETTE RIVER
HILLS CREEK
WALTERVILLE
LEABURG
STRUBE
COUGAR
S. FK. McKENZIE R
McKENZIE RIVER
SMITH R
SMITH RES
CARMEN P.H.
TRAIL BRIDGE DAM & P.H.
DESCHUTES RIVER
PELTON
ROUND BUTTE
0
200
400
600
800
1000
2000
3000
4000
5000
6000
50
100
150



COLUMBIA-NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

CONDENSED PROFILE

MAJOR HYDROELECTRIC POWER
DEVELOPMENT, EXISTING AND POTENTIAL
COLUMBIA RIVER AND MAJOR TRIBUTARIES

1969

FIGURE 6

2

installed (nameplate) capacity. Figure 5 shows the location of the existing and potential projects of the region having a capacity of 5,000 kilowatts or more. Figure 6 shows these projects in profile form.

Subregion 1, Clark Fork-Kootenai-Spokane

Clark Fork River The Clark Fork River, known as the Pend Oreille River below Pend Oreille Lake, drains over 25,000 square miles of forested, rugged, and relatively sparsely settled area in British Columbia, northern Idaho, and western Montana, and has an annual runoff of over 19 million acre-feet. The stream is partially controlled by existing reservoirs; however, major undeveloped sites remain on the Upper Clark Fork, North Fork Flathead River, Lower Flathead River, and Blackfoot River. Major potential sites in the Flathead and Clark Fork basins are tabulated below and further discussed in subsequent paragraphs. Paradise Project, located on the Clark Fork rather than Flathead River, is included in the discussion because it is an alternative for development of the Lower Flathead River. Quartz Creek Project, also located on the Clark Fork, has been included to complete the listing for that area.

Table 24 - Potential Hydro Projects, Subregion 1

Project	Stream	Usable Storage (1,000 ac-ft)	Gross Head (ft.)	Average Annual Energy 3/ (Average MW)	Ultimate Plant Capability (MW)
Spruce Park	M. F. Flathead	600	950	45	380
Glacier View 1/	N. F. Flathead	1,510	273	42	325
Smoky Range 1/	N. F. Flathead	1,510	350	65	330
Ninemile Prairie	Blackfoot	885	284	21	92
H. Buff. Rapids 2/	Flathead	668	160	124	516
Buff. Rap. #2 & #4 2/	Flathead	Pondage	160	131	552
Sloan Bridge 2/	Flathead	400	130	93	412
Knowles 2/	Flathead	3,084	230	180	588
Paradise 2/	Clark Fork	4,080	240	288	1,192
Quartz Creek	Clark Fork	Pondage	130	48	120
Sullivan Creek	Sullivan Cr.	62	548	7	16
Kootenai Falls	Kootenai	Pondage	160	107	345
Libby Reregulator	Kootenai	Pondage	48	31	50
Enaville	Coeur d'Alene	700	272	28	80
Subtotal 4/		4,425	2,902	476	1,929

1/ Alternative developments for North Fork Flathead River.
2/ Alternative developments for Lower Flathead River.
3/ At-site generation only.
4/ Spruce Park, Smoky Range, Ninemile Prairie, High Buffalo Rapids, Quartz Creek, Kootenai Falls, Libby Reregulator, Enaville, and Sullivan Creek.
5/ 558 average megawatts, *including generation at downstream projects.*

Spruce Park The project was last investigated in joint studies made by the Bureau of Reclamation and the Corps of Engineers leading to a Memorandum Report on the Clark Fork Basin, September 1967. The damsite is located on the Middle Fork of the Flathead River, 50 miles above its confluence with the North Fork. The dam would be an earth and rockfill structure about 400 feet in height. The reservoir at normal pool elevation 4,480 feet would extend 15 miles up the Middle Fork. Gross storage would be 610,000 acre-feet, of which 600,000 acre-feet would be usable for flood control and power generation. Coordinated operation with Hungry Horse Reservoir would result in a total of 700,000 acre-feet of effective storage for control of major floods. A 22-foot diameter, 8-mile long pressure tunnel through the Flathead Range would deliver water to a powerplant located on the shore of Hungry Horse Reservoir. The rated head would be about 860 feet. Two generators would provide a total installed capacity of 380,000 kilowatts. The average annual generation is estimated at 45,000 kilowatts at-site plus 20,000 kilowatts added annually at downstream hydroelectric plants. The damsite is located on a stream designated for study for possible inclusion in the National Wild and Scenic Rivers System. (38)

Glacier View Dam and Reservoir The damsite is located on the North Fork of Flathead River, 74 miles upstream from Flathead Lake and 39 miles downstream from the International Boundary. This multiple-purpose project is an alternative to the Smoky Range development described below. The dam would consist of a zoned-earthfill embankment about 290 feet in height and have a crest length of approximately 1,800 feet. Gross storage capacity at normal full pool elevation 3,600 feet would be 1,800,000 acre-feet. Usable storage between full and minimum pool elevation 3,465 feet would be 1,510,000 acre-feet. Initial installation would consist of three generating units and provisions for future installations of two additional units to provide a total ultimate capacity of 325,000 kilowatts. Average annual generation would be about 42,000 kilowatts at-site with 15,000 kilowatts added annually at downstream plants. The project was investigated jointly by the Bureau of Reclamation and the Corps of Engineers in a study leading to a Memorandum Report on Clark Fork Basin, September 1967. The project was initially investigated in studies presented in House Document 531. That report proposed a project having a full pool elevation of 3,725 feet providing usable storage of 3,160,000 acre-feet out of a total storage of 4,800,000 acre-feet. The project was not recommended for construction because of objections by the National Park Service and by recreation interests concerning possible adverse effect on wildlife range and recreational use of the western section of Glacier National Park. The damsite is located on a stream designated for study for possible inclusion in the National Wild and Scenic Rivers System. (30, 38)

Smoky Range Dam and Reservoir This project is an alternate to development of Glacier View. Smoky Range damsite is located on the North Fork of Flathead River, 63 miles upstream from Flathead Lake and 50 miles downstream from the International Boundary. The dam would be a zoned-earthfill embankment having a maximum height of 370 feet above bedrock and a crest length about 3,500 feet. At full pool elevation 3,550 feet, the reservoir would extend upstream 26 miles and submerge the Glacier View damsite. Usable storage for flood control and power would be 1,510,000 acre-feet with a drawdown of 175 feet. Initial installation would include three 66,000 kilowatt generating units with provisions for future installation of two additional 66,000-kilowatt units to provide a total generating capacity of 330,000 kilowatts. Average annual generation would be about 65,000 kilowatts at-site and about 12,000 kilowatts would be added annually at downstream plants. The project was also included in the 1967 study of the Clark Fork Basin. The project was initially investigated in studies presented in House Document 403, 87th Congress, 2d Session. That report proposed the same project as described above but with a smaller powerplant installation. The project was not recommended for construction because the Secretary of the Interior requested that further considerations of this project be dropped because of adverse effect on Glacier National Park and on the fish and wildlife resources of the impoundment site and related areas. The damsite is located within the area designated for study for possible inclusion in the National Wild and Scenic Rivers System.(33, 38)

Buffalo Rapids No. 2 and No. 4 This is one of five alternative schemes for development of the Flathead River downstream from Kerr Dam. Application for joint license was filed March 9, 1965, for Buffalo Rapids Project No. 2507 by the Confederated Salish and Kootenai Tribes of the Flathead Reservation, and the Montana Power Company. The Buffalo Rapids No. 2 damsite is located on the Flathead River at river mile 60.7. The reservoir at full pool elevation 2,702 feet would extend upstream to the tailwater of Kerr Dam. Storage would be limited to pondage, and the gross head would be 80 feet. The Buffalo Rapids No. 4 damsite is located on the Flathead River at river mile 36.5. The reservoir at full pool elevation 2,619 feet would extend upstream to the tailwater of Buffalo Rapids No. 2. Storage would be limited to pondage, and the gross head would be 80 feet. Each powerplant would contain two 60,000 kilowatt units. The combined average annual generation of the two projects is estimated at 131,000 kilowatts. Total peaking capability is estimated at 276,000 kilowatts. Studies presented in Memorandum Report on the Clark Fork Basin considered each powerplant would ultimately contain four units providing a combined peaking capability of 552,000 kilowatts for the total development. (38)

High Buffalo Rapids No. 4 High Buffalo Rapids No. 4 is another alternative for development of the Lower Flathead River. The damsite is located on the Flathead River, 36.5 miles upstream from the confluence of the Flathead River with the Clark Fork and about 11.5 miles above the town of Dixon, Montana. The dam proposed in House Document 403 would consist of a concrete-gravity intake structure tied into an earthfill dam. The concrete-gravity intake structure would have a maximum height of about 280 feet above bedrock and would be 1,300 feet long. The earthfill section would have a maximum height of 160 feet above natural ground and would be 8,600 feet long. The reservoir at normal full pool elevation 2,700 feet would provide 668,000 acre-feet usable storage with a drawdown of 67 feet. Gross head for power would be 164 feet. The power installation proposed in House Document 403 would consist of 4 units, each having a rated capacity of 56,000 kilowatts, with a substructure for future installation of one additional unit of the same capacity. Studies presented in the Memorandum Report on Clark Fork Basin considered an ultimate powerplant installation totaling 516,000 kilowatts in eight units. Average annual generation for the latter installation is estimated at 124,000 kilowatts at-site plus 7,000 kilowatts added at downstream plants. (33, 38)

Sloan Bridge This project is an alternative plan for development of the Flathead River below Kerr Dam. The damsite is on the Flathead River about midway between Buffalo Rapids No. 2 and Buffalo Rapids No. 4 sites, 44.7 miles upstream from the confluence with the Clark Fork and 27.8 miles downstream from Kerr Dam. The reservoir at full pool elevation 2,700 feet would extend upstream to the tailwater of Kerr Dam. The gross storage would be 512,000 acre-feet, of which 400,000 acre-feet would be usable for flood control and power generation. Gross head would be 130 feet. Eight units would provide a total generating capacity of 412,000 kilowatts. Average annual energy generation is estimated at 93,000 kilowatts at-site plus 3,000 kilowatts added at downstream plants.(38)

Knowles Dam and Reservoir The damsite is located near the mouth of Flathead River, 2.7 miles upstream from its confluence with the Clark Fork. The reservoir at full pool elevation 2,700 feet would extend upstream on the Flathead River to tailwater of Kerr Dam and submerge the Buffalo Rapids and Sloan Bridge damsites. As proposed in House Document 403, the main dam would be a zoned-earthfill embankment with a maximum height of 266 feet above streambed and a top length of 2,050 feet including a concrete gravity nonoverflow wraparound section. A concrete gravity intake structure and spillway section would be tied into the earthfill dam section. Gross storage would be 4,959,000 acre-feet, of which 3,084,000 acre-feet would be usable for flood control and power

generation. Gross head would be 230 feet. The reservoir would inundate 28 miles of the main line of the Northern Pacific Railway and 7 miles of the Polson branch line. It would also inundate 14 miles of petroleum pipeline, 28 miles of U.S. Highway 10-A, and 87 miles of county, Forest Service, and National Bison Range roads. Approximately 9,000 acres of irrigated land and 1,600 acres of unirrigated cultivated land, and 36,400 acres of pasture and grazing land including a portion of the National Bison Range are located in the reservoir area. The powerplant considered in the Memorandum Report on Clark Fork Basin, September 1967 (7), consists of eight units providing a total installed capacity of 588,000 kilowatts. Average annual generation is estimated at 180,000 kilowatts at-site. (33, 38)

Paradise Project The damsite is located on the Clark Fork approximately 105 miles upstream from Pend Oreille Lake and four river miles downstream from the mouth of the Flathead River. Paradise Dam and reservoir project is an alternate plan of development for the Flathead River below Kerr Dam. The reservoir at full pool elevation 2,700 feet would extend upstream on the Flathead River to the tailwater of Kerr Dam, submerging the Knowles, Buffalo Rapids, and Sloan Bridge damsites, and back water 46 miles up the Clark Fork. Gross storage would be 6,500,000 acre-feet, of which 4,080,000 acre-feet would be usable for flood control and power generation. The dam would effectively control downstream flows from both the Clark Fork and the Flathead River. Gross head would be 240 feet. The main dam would be a zoned-earthfill embankment with a maximum height of 270 feet above streambed and a top length of 3,750 feet. A concrete-gravity intake structure and spillway would be tied into the main earthfill dam and a saddle dam across a side channel. The Paradise Project would require substantial relocations. The Northern Pacific Railway operates two main lines from DeSmet to Paradise and parts of both of these lines lie in the reservoir area. The Polson branch line would have to be relocated. About 13 miles of Chicago, Milwaukie, St. Paul, and Pacific Railroad would require relocation to higher ground. About 14 miles of Interstate highway and 38 miles of primary Federal and State highways also would require relocation. The reservoir at full pool would inundate about 9,000 acres of irrigated land; about 3,700 acres of nonirrigated, cultivated land, and 38,600 acres of pasture and grazing land, including a portion of the National Bison Range. The Memorandum Report on Clark Fork Basin, September 1967, considered a project with an ultimate power installation of 12 units providing a total plant capacity of 1,192,000 kilowatts. The project would generate an annual average of 288,000 kilowatts. (33, 38)

Quartz Creek This would be a single-purpose, run-of-river power project. The damsite is located on the Clark Fork, 56.5 miles upstream from its confluence with the Flathead River, and 19 miles upstream from Superior, Montana. A concrete-gravity dam 180 feet high with a total length of 600 feet would develop a gross head of 130 feet for at-site power generation. The reservoir at full pool elevation 2,895 feet would extend up the Clark Fork for 10 miles. Storage would be limited to pondage with a pool fluctuation of about 2 feet. Relocations would include 1.3 miles of Chicago, Milwaukie, St. Paul and Pacific Railroad, 0.5 mile of Northern Pacific Railway main line, and about 0.6 mile of secondary roads. The powerplant installation would consist of four generating units providing a total of 120,000 kilowatts. Average annual energy production is estimated at 48,000 kilowatts. (38)

Ninemile Prairie Dam and Reservoir This would be a multiple-purpose project located on the Blackfoot River in Missoula County, Montana. The damsite is about 22 miles upstream from the confluence of Blackfoot River with the Clark Fork. This site was investigated in studies leading to preparation of House Document No. 403. A project at the Ninemile Prairie site has also been studied by the Bureau of Reclamation and the data contained in House Document No. 403 were derived from a report dated June 1958, by the Regional Director of Region 1 to the Commissioner of the Bureau of Reclamation. The dam would be a zoned, rolled, earthfill structure with a height of 300 feet above streambed and a crest length of 1,700 feet. The reservoir at normal full pool elevation 3,819 feet would extend 14 miles upstream to a point 4 miles above the confluence of the Clearwater River and the Blackfoot River. The reservoir would provide 1 million acre-feet of storage capacity of which 885,000 acre-feet would be usable for flood control and power generation. The powerplant would contain three 20,000 kilowatt generating units. Studies presented in Memorandum Report on Clark Fork Basin, September 1967 (7), considered a powerplant having four generating units to provide a total installed plant capacity of 92,000 kilowatts. At-site, power generation would average 21,000 kilowatts annually and downstream production would be increased 9,000 kilowatts annually.(33, 38)

Sullivan Creek The project would be located in the northeast corner of the State of Washington, a few miles from the International Boundary, on Outlet Creek and Sullivan Creek in the vicinity of Metaline Falls. Application for license for this project was filed on June 14, 1965, by Public Utility District No. 1 of Pend Oreille County, Washington. The project would consist of an earth and rockfill dam maintaining a pool elevation of 2,594 feet, providing approximately 61,600 acre-feet of storage, and a powerhouse containing two 6,800 kilowatt units. Average annual generation would be

about 7,000 kilowatts. The project would replace the existing Sullivan Lake Project, which is presently operated only for storage. Federal Power Commission action is pending on the application.(9)

Kootenai River The Kootenai River drainage basin is located in southeastern British Columbia, northwestern Montana, and northern Idaho. Three-fourths of its drainage area and two-thirds of its length are in British Columbia. This study deals only with that portion located in the United States. The Kootenai River enters the United States at Gateway, Montana, about 190 miles downstream from its source, where it begins a long, sweeping U-shaped course that takes it 40 miles into Montana and back into Canada after cutting diagonally across the tip of the Idaho panhandle. The average annual runoff at Libby, Montana, based on 54 years of record, is about 8,700,000 acre-feet. Several potential power sites were investigated in studies leading to House Document 531 and 403. (30, 33) Based upon information presented in those reports, all have been eliminated from further consideration except for Kootenai Falls Project and Libby Reregulation Dam. Studies have not progressed to determine whether power facilities will be included at the Libby Reregulation Project.

Libby Reregulator A reregulating dam must be constructed below Libby Dam to permit full utilization of Libby's peaking potential while still maintaining stable flow conditions in the Kootenai River downstream. The reregulating dam was authorized as a part of the Libby Reservoir project, but additional authorization would be needed for a power installation. As a part of their current Columbia River and Tributaries Study, the Corps of Engineers is making studies to determine the feasibility of installing power. Site selection studies have indicated that a project at river mile 208.9 having a normal full pool elevation of 2,130 feet would best fill the reregulation needs. Preliminary power studies indicate that a powerplant would be justified at the reregulator. These studies were based on a 4-unit powerplant having a nameplate rating of 43,800 kilowatts. Maximum head would be about 54 feet and average annual energy about 30,600 kilowatts.

Kootenai Falls This would be a single-purpose run-of-river power project located about 4 miles upstream from Troy, Montana. A concrete dam, 153 feet high with a total length of 1,340 feet, would develop a gross head of 160 feet for generation of power. At normal pool elevation 2,060 feet, the reservoir would extend upstream about 15 miles. Major relocations would include about 16.5 miles of Great Northern Railway main line, 7 miles of U.S. Highway 2, and

10 miles of forest roads. Powerplant installation would total about 300,000 kilowatts. Average annual generation is estimated at 107,000 kilowatts.(8, 33)

Coeur d'Alene River The Coeur d'Alene River drains the western slope of a portion of the Bitterroot Range and flows southerly and westerly to enter Coeur d'Alene Lake about 15 miles due south of the city of Coeur d'Alene, Idaho. The potential of Coeur d'Alene River for water resource development was investigated in studies presented in House Document 531. (30) The studies considered a multiple-purpose project at the Springston site at river mile 3.5, and a future project at the Leland Glen site at river mile 55.0, as the most favorable plan for developing the stream. The plan was not recommended in House Document 531 because of the economic impact on the area which would be inundated. The Enaville Project was also considered in the 1948 studies, but was eliminated because this site would control only 60 percent of the mean runoff; whereas the combination of Springston and Lelan Glen would fully control the mean runoff of the stream. In studies presented in House Document 403 (33), the Enaville site was selected because development would avoid the possibility of damage to mining interests and still provide reasonable control of runoff for flood control and power.

Enaville Project The damsite is located on the Coeur d'Alene River, adjacent to the town of Enaville, Idaho, 35.6 miles upstream from Coeur d'Alene Lake and 1.2 miles upstream from the confluence of the main river with the South Fork of Coeur d'Alene River. The dam would be a rockfill embankment with a maximum height of 280 feet above streambed and a top length of 1,550 feet. The spillway would be a concrete gravity spillway section with a crest length of 135 feet. The powerhouse and outlet structure would be located near the toe on the right side of the spillway and would be served by a 25-foot diameter steel-lined tunnel driven through rock under the right abutment. The reservoir would have a total capacity of 1,012,000 acre-feet at full pool elevation 2,430 feet. Usable storage would be 700,000 acre-feet for flood control and power with a drawdown of 106 feet. At full pool the reservoir would have a surface area of 9,000 acres, all of which is within the boundaries of Coeur d'Alene National Forest. As reported in House Document 403, the project would have one 43,000-kilowatt unit installed. Based on present criteria, the plant would have an installed capacity of 70,000 kilowatts and a peaking capability of about 80,000 kilowatts. Average annual generation would be 28,000 kilowatts at-site. Average annual generation downstream would be increased by 34,000 kilowatts.(33)

Subregion 2, Upper Columbia

This subregion consists of the streams that drain into the mainstem Columbia between Richland, Washington, and the Canadian border. Potential projects in this subregion include Sullivan Creek, on a minor tributary; the four-dam Wenatchee River Project; and Ben Franklin, on the Columbia.

Table 25 - Potential Hydro Projects, Subregion 2

Project	Stream	Usable Storage (1,000 ac-ft)	Gross Head (ft.)	Average Annual Energy (Average MW)	Ultimate Plant Capability (MW)
Chiwawa	Wenatchee R.	400	672	20	145
Beaver Creek	Wenatchee R.	32	60	7	14
Leavenworth	Wenatchee R.	Pondage	620	67	120
Dryden	Wenatchee R.	Pondage	87	11	20
Ben Franklin	Columbia R.	Pondage	60	428	938
TOTAL		432	1,499	533	1,237

Wenatchee River The Wenatchee River drains a segment of the eastern slope of the Cascade Range through its three principal tributaries, Little Wenatchee, White, and Chiwawa rivers. The Little Wenatchee and White are tributary to Wenatchee Lake, which is the source of the main Wenatchee River. The Chiwawa joins the Wenatchee about 5 miles downstream from the lake. The Wenatchee River is about 47 miles long and flows in a southeasterly direction to enter the Columbia at mile 468.4. The drainage basin of the Wenatchee River totals about 1,350 square miles. Potential multiple-purpose sites investigated in studies leading to House Document 531 (30) included Plain Site on Wenatchee River and Chiwawa Site on Chiwawa River. These sites were further reviewed in studies leading to House Document 403 (33). More recently an Application for License has been filed with Federal Power Commission by Chelan County PUD No. 1 for Wenatchee Project No. 2151-Washington. An amended application submitted in June 1965 proposes four developments as follows:

Chiwawa The Chiwawa development would consist of an impervious core earthfill dam located on the Chiwawa River, upstream from Big Meadow Creek, with full pool at elevation 2,545 feet, a 5.8 mile penstock tunnel; and the Dirtyface Mountain powerhouse on Lake Wenatchee, containing three units totaling 145,000 kilowatts and operating under a gross head of 672 feet. One of these units would be an 80,000 kilowatt conventional unit and the other two, 20,000 kilowatts and 45,000 kilowatts, respectively, would be reversible pump-turbines. Usable storage in the Chiwawa Reservoir would be 400,000 acre-feet. Average annual generation would be about 20,100 kilowatts.(23)

Beaver Creek The Beaver Creek development would consist of an earthfill and concrete-gravity dam on the Wenatchee River, upstream from the junction with Beaver Creek, providing a pool elevation of 1,873 feet and a powerhouse containing two generating units, one 4,000 kilowatts and one 10,000 kilowatts, operating under a gross head of 60 feet. The Beaver Creek Dam would control Wenatchee Lake and would provide 32,000 acre-feet of usable storage in the upper 10 feet. Average annual generation would be about 7,300 kilowatts. (23)

Leavenworth The Leavenworth development would consist of of an earthfill diversion dam near Chiwaukum Creek on the Wenatchee River, with a pool elevation of 1,750 feet; a 7-mile tunnel and penstock; and a powerhouse containing two generating units, one 80,000 kilowatts and one 40,000 kilowatts, operating under a gross head of 620 feet. Six thousand acre-feet of pondage would be available behind the Chiwaukum Creek Dam. Average annual generation would be about 67,000 kilowatts. (23)

Dryden This project would consist of a new concrete diversion dam at the site of the existing dam on the Wenatchee River raising the water elevation an additional 11 feet, a 3,600-foot-long canal to forebay, and a powerhouse containing two 10,000-kilowatt units operating under a gross head of 87 feet. Average annual generation would be about 11,000 kilowatts. (23)

Mainstem Columbia River On the Columbia River from the head of McNary reservoir (Lake Wallula) to Priest Rapids tailwater, approximately 65 feet of head remain undeveloped. The reach was investigated in 1948 in studies leading to preparation of House Document No. 531. Sites found to be physically feasible from seismic surveys were the Ringold site at river mile 355 and the Richland site at river mile 348. Subsequent field explorations and office studies indicated the Richland site to be more favorable. The site is now referred to as the Ben Franklin site.

Ben Franklin Dam Development of the Ben Franklin site was reviewed in 1958 in studies leading to preparation of House Document 403. A survey report dated July 1969, prepared by the Seattle District, Corps of Engineers, recommends that the Ben Franklin multiple-purpose project be authorized for construction. The damsite is located at the head of McNary reservoir, 10 miles upstream from Richland, Washington, 13 miles above the mouth of the Yakima River, and 23 miles above the mouth of the Snake River. It is 49 miles downstream from Priest Rapids Dam. The Columbia River above the damsite drains 97,000 square miles in the United States and Canada. As proposed in the feasibility report, the plan consists of a powerhouse, 15-bay spillway designed to pass a flow

of 1,600,000 cubic feet per second, and earthfill dams connecting to the abutments on each side. An earthfill dam about 600 feet long would connect the spillway to the left abutment. On the right bank, the earthfill dam would extend 7,100 feet from the powerhouse to the right abutment. At full pool elevation 400 feet, the gross head for power generation would be 60 feet. The powerhouse would contain 16 generating units having a total installed capacity of 976,000 kilowatts. Average annual generation is estimated at 428,000 kilowatts.(42)

Subregion 3, Yakima River

There are no potential hydroelectric projects in the subregion.

Subregion 4, Upper Snake River

This subregion consists of the drainage basin of the Snake River above King Hill. Important tributaries in this subregion are the Henrys Fork, Greys, and Hoback rivers.

Table 26 - Potential Hydro Projects, Subregion 4

Project	Stream	Usable Storage (1,000 ac-ft)	Gross Head (ft.)	Average Annual Energy (Average MW)	Maximum Plant Capability (MW)
Thousand Springs	Snake River	400	174	53	150
Lynn Crandall	Snake River	1,250	270	122 1/	375 1/
Clark Ranch	Snake River	27	40	16	30
American Falls	Snake River	Existing	58	21 2/	19 2/
Eagle Rock	Snake River	Pondage	43	16	30
Mesa Falls	Henrys Fork	Pondage	210	12	15
Warm River	Henrys Fork	75	220	22	35
Ashton	Henrys Fork	40	87	4 2/	6 2/
Granite Creek	Hoback R.	403	315	6	16
Elbow	Greys River	310	330	6	14
Alpine	Snake River	878	430	111	270
Totals		3,413	2,177	389	960

1/ Includes 20 MW of energy and 375 MW of capability from powerplant expansion at Palisades.
2/ Incremental additions of reconstructed project.

Thousand Springs The damsite is located at river mile 584.3 on the Snake River immediately downstream from the existing Thousand Springs powerplant of the Idaho Power Company, southwest of Wendell, Idaho. The dam would be a zoned earthfill embankment with a maximum height of 194 feet. With a normal pool elevation of 3,054 feet, total reservoir storage would be 595,000 acre-feet, of which 400,000 acre-feet would be usable for power production and flood control. The powerplant would have an installed capacity of 150,000 kilowatts in three units. At-site power generation would average about 53,000 kilowatts annually.(32)

Lynn Crandall The damsite is located on the Snake River at mile 872.5, about 30 miles downstream from the existing Palisades Dam. The dam would be an earthfill structure, 290 feet in height above streambed having a crest length of 2,500 feet. The reservoir at maximum pool elevation 5,375 feet would provide 1,460,000 acre-feet of storage capacity of which 1,280,000 acre-feet are usable for power generation, irrigation, flood control, and reregulation of Palisades discharges. Installed capacity would consist of four units of 60,000 kilowatts each. Maximum gross head would be 270 feet. The project is under investigation by the Bureau of Reclamation.

Included as part of the development will be the addition of 135,000 kilowatts of peaking capability at Palisades Dam. The two new units would be housed in a separate power plant downstream from the existing Palisades plant. Water would be conveyed to the new plant through a tunnel which would tap into the present outlet tunnel. (22, 24)

Lynn Crandall would be an earthfill structure at mile 872.5 on the Snake River (Bureau of Reclamation).

American Falls The proposed power plant would be located at the existing American Falls Dam. The powerplant is authorized for construction by the Bureau of Reclamation. The powerplant would contain three 10,000-kilowatt generating units. Replacement of American Falls Dam is currently under study. Such studies will include resizing and redesign of the powerplant. (23, 24)

Clark Ranch The reregulator for the power producing complex Palisades and Lynn Crandall, the Clark Ranch damsite, is located at about mile 865 on the Snake River. The dam would be an earthfill structure providing about 27,000 acre-feet at normal pool elevation 5,094 feet. A 30,000-kilowatt powerplant with gross head of about 40 feet would provide average annual generation of about 16,000 kilowatts. (12, 24)

Eagle Rock Dam and Powerplant The dam would be located on the Snake River at about river mile 708.4, about 70 miles upstream from Milner Dam and 7 miles downstream from American Falls, Idaho. The dam would be an earthfill structure with a maximum height above streambed of about 45 feet and a crest length of nearly 1,500 feet. Total installed capacity would be about 30,000 kilowatts. All releases passing American Falls Dam would be available for power generation at the Eagle Rock project. Average energy generation is estimated at 16,300 kilowatts annually. (32)

Mesa Falls Project The damsite is located on the Henrys Fork of Snake River, about 15 miles by road northeast of Ashton, Idaho. The project would consist of facilities to develop the head created by Upper and Lower Mesa Falls.

Mesa Falls Diversion Dam would be located just upstream from Upper Mesa Falls. It would be an earthfill-type structure with a maximum height of 40 feet above streambed and a crest length of 240 feet. The normal water surface of the reservoir would be at elevation 5,680 feet. A penstock would run about one mile from the diversion dam to a powerplant to be located downstream from the lower falls. The 15,000-kilowatt powerplant would operate under a static head of about 210 feet. Average annual energy is estimated at about 11,600 kilowatts. (32)

Warm River The damsite is located about 8 miles northeast of Ashton, Idaho, on the Henrys Fork of the Snake River, approximately one-quarter mile downstream from the confluence of Henrys Fork and Warm River. The dam would be a rockfill structure about 265 feet in height and 1,600 feet in length at crest elevation 5,485 feet. The reservoir would have a total capacity of 140,000 acre-feet at normal pool elevation 5,470 feet, of which 75,000 acre-feet would be usable for power production and flood control based upon 70 feet drawdown. With maximum reservoir elevation at 5,478 feet, the pool would extend upstream to the Mesa Falls project. Power generating facilities would consist of two units providing a total installation of 35,000 kilowatts. Average annual generation is estimated at 22,000 kilowatts. (23, 32)

Ashton Dam This is an existing project constructed in 1917, on the Henrys Fork of the Snake River, about 2 miles west of the town of Ashton, Idaho. The present dam, which has a 5,800-kilowatt powerplant, is owned and operated by Utah Power and Light Company. Reconstruction of Ashton Project would more fully develop the potential of the site to meet increased demands for flood control and power. The present dam would be inundated by the proposed structure which would be located about 400 feet downstream from the existing development. The proposed dam would be a concrete-gravity structure about 105 feet in height above streambed and 3,020 feet long at crest elevation 5,200 feet. An earthfill section about 2,300 feet long would also be required. The reservoir would provide 48,700 acre-feet total capacity, of which 40,000 acre-feet would be usable for power generation and flood control. A 12,000 kilowatt powerplant would generate approximately 7,800 kilowatts annually.(23, 32)

Granite Creek The damsite is located on the Hoback River in western Wyoming, about 13 miles upstream from its confluence with the Snake River. The Granite Creek development appears the best of three alternative sites on Hoback River because of its greater potential for power production, irrigation storage, and flood control. The dam would be earthfill, about 325 feet in height above streambed with a crest length of about 1,350 feet. The reservoir would have a capacity of 470,000 acre-feet, of which 403,000 acre-feet would be usable on a forecast basis to provide water for new irrigation downstream, flood control, and power production. The powerplant would have an installed capacity of 16,000 kilowatts. Average annual generation at-site would be about 6,300 kilowatts. (32)

Elbow Project The damsite is located on the Greys River about 26 river miles upstream from its confluence with the Snake River in Lincoln County of western Wyoming. The dam would be of the earthfill type about 356 feet in height above streambed, having a crest length of approximately 2,300 feet. The 450,000 acre-foot reservoir could provide 310,000 acre-feet of usable capacity. This storage, operated in conjunction with Alpine and Granite Creek reservoirs on a forecast basis, would provide a maximum amount of water for new irrigation downstream, and for flood control and power production. The powerplant would be located adjacent to the control house near the left downstream toe of the dam and would have an installed capacity of 14,000 kilowatts. Average energy generation at-site is estimated at 5,600 kilowatts annually.(32)

Alpine Dam and Reservoir The Alpine site is considered to be the most favorable remaining site for major multipurpose storage development in the Upper Snake River Basin. The site is located on the Snake River about 3 miles upstream from the Wyoming-Idaho State Boundary. The dam would be a rolled-earthfill structure about 440 feet in height above foundation, and about 1,280 feet long at the crest. The reservoir at full pool elevation would provide a total of 1,078,000 acre-feet of storage, of which 878,000 acre-feet would be usable for power generation, irrigation, and flood control. The powerplant would provide a total capacity of 270,000 kilowatts. Annual average at-site generation is estimated at 111,400 kilowatts. The addition of the Alpine reservoir to the system would allow greater flexibility in operation of Jackson Lake and thereby enhance its use for recreational purposes. (32)

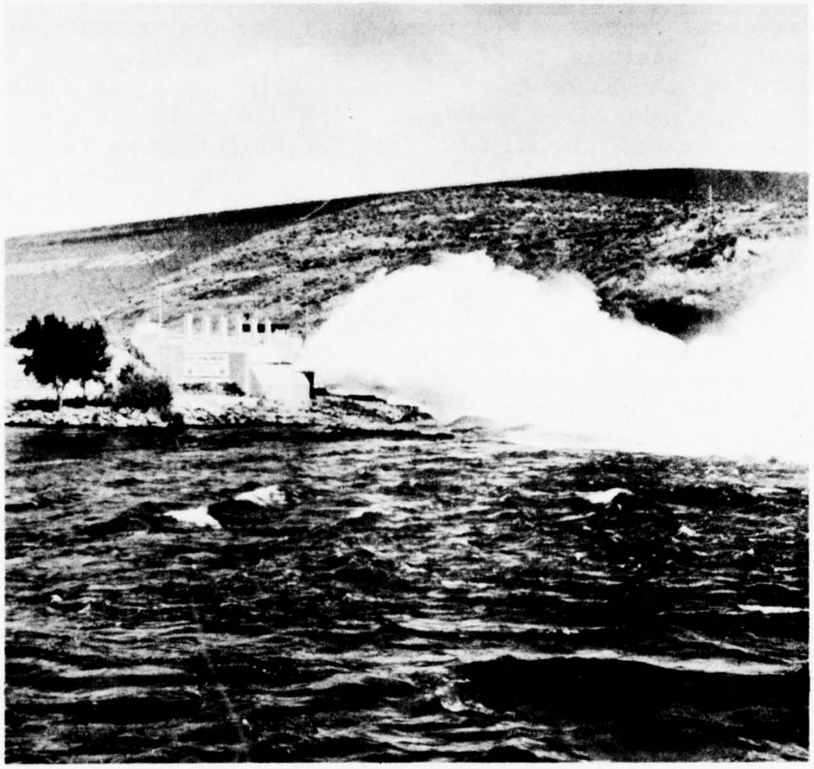
Subregion 5, Central Snake

This subregion consists of the drainage of the Snake River below King Hill, Idaho, and above Oxbow Dam on the Oregon-Idaho border. Important tributaries in this subregion are the Bruneau, Boise, Owyhee, Payette, and Weiser rivers.

Table 27 - Potential Hydro Projects, Subregion 5

Project	Stream	Usable Storage (1,000 ac-ft)	Gross Head (ft)	Average Annual Energy (Average MW)	Maximum Plant Capability (MW)
Lucky Peak	Boise R.	Existing	240	33	106
Twin Springs	Boise R.	490	459	37	104
Garden Valley	S.F. Payette	1,940	415	71	175
G. V. Rereg.	S.F. Payette	Pondage	120	18	36
Upper Scriver	N.F. Payette	Pondage	447	24	38
Lower Scriver	N.F. Payette	Pondage	746	43	120
Guffey (High)	Snake R.	Pondage	103	60	85
Swan Falls-Guffey	Snake R.	Pondage	105	59	186
Duncan Ferry	Owyhee R.	743	210	8	14
TOTAL		3,173	2,740 1/	294 1/	678 1/

1/ Swan Falls-Guffey Project, an alternative to High Guffey, not included in totals.



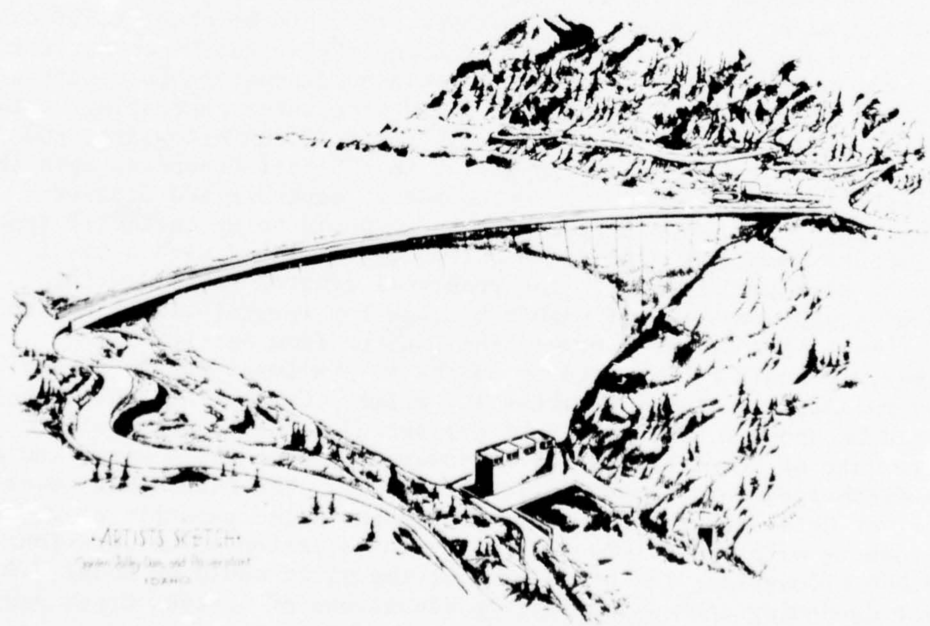
Lucky Peak Project on the Boise River near Boise, Idaho (Corps of Engineers).

Lucky Peak Dam and Reservoir Lucky Peak Dam is an existing earthfill dam 250 feet in height, located on the Boise River about 10 miles east of Boise, Idaho, at river mile 64.5. The project provides 280,000 acre-feet of usable storage for control of destructive floods along the main stem of the Boise River for some 60 miles downstream. The operation of the three Boise River reservoirs (Lucky Peak, Arrowrock, and Anderson Ranch) is coordinated to provide up to 776,500 acre-feet of flood control space during the spring runoff season and ample irrigation water during the valley growing season, with the Lucky Peak Reservoir being maintained as long as possible at a level to permit maximum usage of its recreational facilities. There are no power generating facilities at Lucky Peak at the present time, however, current plans call for providing such facilities if and when Twin Springs project, subsequently discussed, is authorized for construction. Initial installation would consist of two 20,150-kilowatt conventional units with space provided for installation of a third unit at a later date. The third unit would be a reversible pump turbine unit rated at 66,000 kilowatts. Average generation with the ultimate installation is estimated at 32,600 kilowatts annually. A

reregulating dam will be provided downstream to serve as the lower reservoir during pumped-storage operations and to maintain suitable flows downstream. (23, 39)

Twin Springs Project The damsite is located at river mile 103 on the Boise River. The project would consist of a rockfill dam 470 feet high creating a reservoir which, at maximum pool elevation 3,850 feet, would provide 600,000 acre-feet of storage, of which 490,000 acre-feet would be usable for flood control and power generation. Initial installation would consist of two 17,250-kilowatt and one 34,500-kilowatt unit plus space for an additional future unit of 34,500 kilowatts, giving an ultimate installed capacity of 103,500 kilowatts. Average annual generation with the ultimate installation is estimated at 36,600 kilowatts. (23, 29)

Garden Valley Project The damsite is located on the South Fork Payette River about 4 miles below the mouth of the Middle Fork. The dam would be a concrete-arch type about 435 feet in height above streambed and would have a crest length of approximately 1,400 feet. The reservoir at normal water surface elevation 3,335 feet would have a total capacity of 2,400,000 acre-feet of which 1,940,000 acre-feet would be usable for power generation, flood control, and irrigation. The powerplant would have an initial installation of



Diversions from the North Fork of Payette River would be stored at Garden Valley Reservoir (Bureau of Reclamation).

131,250 kilowatts and an ultimate installation of 175,000 kilowatts. A reregulation dam would be located on the South Fork of Payette River about 3 miles downstream from Garden Valley Dam and about one-half mile upstream from the confluence of the South and North Forks of Payette River. The reregulation dam would be a concrete-gravity structure about 130 feet in height above streambed with a crest length of approximately 435 feet. The reregulator powerplant would have an initial installation of 27,000 kilowatts with provisions for future installation of an additional 9,000 kilowatts. The Garden Valley Project, which includes Smiths Ferry diversion, Upper and Lower Scriver, Garden Valley Dam and reregulation, has been recommended for construction by the Bureau of Reclamation. (14)

<u>Upper and Lower Scriver Creek Projects</u> This development involves diversion of flows from the North Fork Payette River through the intervening divide to the South Fork drainage and Garden Valley reservoir. The difference in elevation, about 1,200 feet between the North Fork at Smiths Ferry diversion and Garden Valley reservoir, would be utilized for power production by the Upper and Lower Scriver Creek plants along the diversion route. Smiths Ferry diversion would consist of a concrete-gravity diversion dam about 40 feet in height above streambed with a crest length of about 240 feet, creating a reservoir having normal water surface elevation at 4,528 feet. A concrete intake structure and concrete-lined pressure tunnel would convey water to Scriver Creek, a tributary of the Middle Fork of the Payette River. Tunnel length would be about 4.6 miles and the capacity would be about 1,385 cubic feet per second. The tunnel would terminate at the Upper Scriver Creek powerplant from which water would be discharged into Scriver Creek reservoir. The powerplant would have three generating units, having a total installed capacity of about 37,500 kilowatts, and would operate at a gross head of 445 to 475 feet depending upon the water surface elevations at Smiths Ferry reservoir and Scriver Creek reservoir. The Scriver Creek Dam would be an earthfill type structure about 171 feet in height above streambed with a crest length of about 580 feet. The reservoir created would provide about 4,950 acre-feet of usable storage for reregulating flows to the Lower Scriver Creek powerplant. Water from Scriver Creek reservoir would be diverted by tunnel to the Lower Scriver Creek powerplant, a distance of about 1.1 miles. Capacity of the tunnel would be about 2,500 cubic feet per second. The tunnel would terminate at Lower Scriver Creek powerplant from which water would be discharged into Garden Valley reservoir. The three-unit Lower Scriver Creek powerplant would have an installed capacity of 90,000 kilowatts with provisions for future installation of an additional 30,000 kilowatts. The gross head at the plant would be about 740 feet depending upon water surface elevations of Scriver Creek and Garden Valley reservoirs. (14)

Guffey Project The damsite is located on the Snake River at about river mile 445.5, about 3 miles upstream from Walters Ferry Bridge. The reservoir at maximum normal water-surface elevation 2,354 feet would have a total capacity of about 332,000 acre-feet, of which 27,000 acre-feet would be usable for power production and irrigation. The plan proposed for construction by the Bureau of Reclamation consists of an earthfill dam about 190 feet in height above streambed, a powerplant containing four generating units with a total installed capacity of 85,000 kilowatts, and the necessary pumping, distribution canals and drainage facilities to irrigate the Dry Lake area and the lands on the south side of Snake River downstream from Guffey Dam. An alternative to this project is the Swan Falls-Guffey project discussed below. (14, 24)

Swan Falls Guffey Project Idaho Power Company has proposed to redevelop the existing Swan Falls project located on the Snake River in Idaho at river mile 455.9, and to construct a reregulating dam at the Guffey site. The Swan Falls redevelopment would consist of a new rockfill dam and powerplant at the site of the existing development. The new dam would be higher and the powerplant would be larger in capacity than the existing project. The reservoir would extend 29 miles upstream to the town of Grandview. The plant would be operated as a run-of-river plant utilizing the discharges from the existing C. J. Strike plant upstream. The Guffey development would consist of an earthfill reregulating dam, reservoir, and powerplant. The reservoir would extend 12 miles upstream to the Swan Falls development. Maximum static head would be 65 feet at Swan Falls and 40 feet at Guffey. The initial installation at Swan Falls would be four 22,500 kilowatt units with provision for three more, giving a total initial capacity of 90,000 kilowatts and an ultimate capacity of 157,000 kilowatts. The Guffey Reregulator would have two units, rated at 14,500 megawatts each. However, operation of the reregulator would limit dependable capacity to about 21,000 kilowatts. Average annual generation at Swan Falls and Guffey Reregulator would be 38,000 and 21,000 kilowatts, respectively.(24)

Duncan Ferry The damsite is located on the Owyhee River about 75 miles upstream from Owyhee Dam. Duncan Ferry reservoir, operated in conjunction with Owyhee reservoir, would provide supplemental water for the existing Owyhee Project, provide flood control on the Owyhee River, enhance sports fishery, and recreational values of the area, and provide at-site power generation. The dam would be a rolled-earthfill type structure 218 feet in height above streambed and a crest length of about 520 feet. The reservoir would have a total capacity of 1 million acre-feet, of which 635,000 acre-feet would be joint-use capacity for irrigation, power production, and flood control. An additional 108,000 acre-feet

would be used exclusively for power production. Installed capacity at Duncan Ferry powerplant would be 14,000 kilowatts. Average annual energy production is estimated at 8,500 kilowatts.(32)

Subregion 6, Lower Snake

This subregion consists of the drainage of the Snake River below Oxbow Dam and includes the draining of the Imnaha, Salmon, and Clearwater rivers. Also included in this subregion is an undeveloped reach of the Snake River commonly known as the "Middle Snake," for which a number of alternative development plans have been proposed. The potential hydroelectric projects located in this subregion are summarized in table 28.

Table 28 - Potential Hydro Projects, Subregion 6

Project	Stream	Usable Storage (1,000 ac-ft)	Gross Head (ft)	Average Annual Generation (Average MW)	Ultimate Plant Capability (MW)
Asotin	Snake R.	Pondage	104.5	[illegible]14	776
China Gardens1/	Snake R.	Pondage	102.5	190	625
High Mountain Sheep1/	Snake R.	2,250	565	608	3,430
Lower Canyon	Salmon R.	2,500	635	503	2,500
Freedom	Salmon R.	Pondage	205	162	800
Crevice	Salmon R.	2,300	725	435	2,200
Pahsimeroi	Salmon R.	1,042	300	30	125
Challis	Salmon R.	350	320	25	125
Tailholt	S.Fk. Salmon R.	470	550	55	250
Penny Cliffs	M.Fk. Clearwater R.	2,300	5[illegible]2	223	1,000
Lenore	Clearwater R.	Pondage	75	75	375
Peck2/	Clearwater R.	Pondage	352/	382/	1752/
Agatha2/	Clearwater R.	Pondage	532/	582/	27[illegible]
Myrtle	Clearwater R.	Pondage	66	71	350
Lapwai	Clearwater R.	Pondage	35	38	175
TOTAL		11,21[illegible]	4,275	2,629	12,731

1/ For listing of alternative plans for development of Middle Snake, see table 29.
2/ Agatha-Peck is an alternative to Lenore. Only the data for Lenore are included in the totals.

Middle Snake River The reach of the Middle Snake River between Lower Granite reservoir and Hells Canyon Dam remains undeveloped although there are several alternative plans currently being analyzed. A project at Asotin site, Snake River mile 146.5 is authorized for construction by the Corps of Engineers. The Middle Snake River between Asotin reservoir and Hells Canyon Dam could be developed by at least four alternate plans. These are tabulated below and further described in subsequent paragraphs.

Table 29 - Alternative Hydro Developments, Middle Snake River

Project	Usable Storage (1,000 ac-ft)	Gross Head (ft.)	Average Annual Generation1/ (Average MW)	Ultimate Plant Capability (MW)
High Mountain Sheep	2,250	565	608	3,430
China Gardens	Pondage	102.5	190	625
Subtotal	2,250	667.5	798	4,055
Appaloosa	1,500	410	457	2,250
Low Mountain Sheep	Pondage	153	122	360
Subtotal	1,500	563	579	2,610
Pleasant Valley	622	382	391	2,170
Low Mountain Sheep	Pondage	181	188	600
Subtotal	622	563	579	2,770
Nez Perce	4,700	615	957	5,000
China Gardens	Pondage	52.5	100	325
Subtotal	4,700	667.5	1,057	5,325

1/ At-site generation based on 2010 irrigation diversions.

It should be noted that the potential output of the Nez Perce project is considerably larger than the other alternatives. This is because Nez Perce utilizes the flow of the Salmon as well as the Snake. In order to compare the total development potentials of the various plans, Lower Canyon on the Salmon should also be included as a part of all but the Nez Perce plan.

Asotin Project The damsite is at river mile 146.8, the upstream limit of Lower Granite reservoir. The reservoir at normal pool elevation 842.5 feet would extend upstream 26 miles to the China Gardens damsite. At this pool elevation, Asotin Dam will provide 104.5 feet of effective head for power production. The initial installation would be three 135,000 kilowatt units giving a total plant capability at 15 percent overload of 466,000 kilowatts. The ultimate installation would add at least two more units giving a total plant capability of 776,000 kilowatts. Average annual energy production under 2010 irrigation depletions is estimated at 214,000 kilowatts. The project was authorized for construction under provisions of the Flood Control Act of 1962. It will be a run-of-river development for the production of hydroelectric power with provisions for the future addition of a navigation lock. (33, 43)

High Mountain Sheep - China Gardens The High Mountain Sheep damsite is located at river mile 189.0 on the Snake River about one-half mile above the confluence with the Salmon River and about 2.7 miles below the mouth of the Imnaha River. The development proposed by Pacific Northwest Power Company and Washington Public Power Supply System in a joint application to the Federal Power Commission consists of a concrete arch type dam approximately

670 feet high to provide a full reservoir elevation of 1,510 feet extending 58 miles up the Snake River to Hells Canyon Dam. The project would provide 2,250,000 acre-feet of usable storage for flood control and power generation. Penstock intakes would be set at an elevation low enough to permit maximum withdrawal of 3,100,000 acre-feet if needed. The initial installed capacity has been tentatively established at 1,290,000 kilowatts in three units and an ultimate generating capacity in seven units of 3,010,000 kilowatts. The plant capabilities (at overload rating) would be about 15 percent higher. The gross head for power with tailwater elevation 940 feet, China Gardens pool elevation, would be 565 feet. Under 2010 irrigation depletions, the project would generate an average of about 608,000 kilowatts annually. Facilities for trapping adult salmon at High Mountain Sheep and transporting them elsewhere for propagation would be incorporated in the development.(19)

While China Gardens was not included as a part of the 1969 amended application, it would be required for full development of this reach. The damsite is located on the Snake River at mile 172.5, about 16 miles below the mouth of the Salmon River. The dam would develop 102.5 feet effective head between High Mountain Sheep and Asotin. The dam would be a straight concrete-gravity type with a normal pool elevation 945 feet. The initial installation would be three 110,000 kilowatt units, giving a total plant capability of 375,000 kilowatts. The ultimate installation would be five units, giving a total plant capability of 625,000 kilowatts. Average annual generation under 2010 conditions would be 190,000 kilowatts.(15)

Appaloosa-Low Mountain Sheep This development is an alternative to High Mountain Sheep development. The Appaloosa damsite is located on the Snake River at mile 197.6, approximately 8 miles upstream of the High Mountain Sheep damsite. The dam would be a concrete arch structure, having a maximum height of about 600 feet. At normal full pool elevation 1,510 feet, the project would provide 1,500,000 acre-feet of usable storage for flood control and power generation. The initial installation would consist of a four-unit powerhouse having a total installed capacity of 1,300,000 kilowatts and plant capability at 15 percent overload of 1,500,000 kilowatts. Ultimately, two more units would be added, giving a total installed capacity of 1,950,000 kilowatts and a capability of 2,250,000 kilowatts. Under 2010 conditions, the project would generate on the average about 457,000 kilowatts. Since the Appaloosa project is located farther upstream on the Snake River than High Mountain Sheep, less land would be flooded. The plan also leaves an open stretch of the river from the Low Mountain Sheep reregulator, past the mouths of the Imnaha and Salmon Rivers, and down to the head of the pool behind Asotin Dam. Facilities for trapping adult Salmon at Low Mountain Sheep and transporting them elsewhere for propagation would be included in the development.

An integral part of the Appaloosa alternative, as proposed in the amended joint application filed by PNPCo and WPPSS, the Low Mountain Sheep reregulating dam would be a concrete gravity structure, located at mile 192.5 on the Snake River, about 0.75 miles upstream from the mouth of the Imnaha River. About 30,000 acre-feet of reregulation storage would be provided in 70-feet drawdown between maximum pool elevation 1,100 feet and minimum pool elevation 1,030 feet. The initial installed capacity would be 156,000 kilowatts and the ultimate capacity 312,000 kilowatts. At 15 percent overload, the plant capabilities would be 180,000 and 360,000 kilowatts, respectively. Average annual generation under 2010 conditions would be about 122,000 kilowatts.(19)

Pleasant Valley-Low Mountain Sheep This plan, which also includes reregulation at Low Mountain Sheep, was the plan proposed by Pacific Northwest Power Company in their original license application in 1955. Now included again, as one of the three alternatives in the 1969 joint application, the Pleasant Valley damsite is located on Snake River at mile 213.0, about 15-1/2 miles upstream from the Appaloosa damsite. Like High Mountain Sheep and Appaloosa, the dam would be of concrete arch construction and would be about 550 feet high. At normal full pool elevation 1,510 feet, usable storage totaling 622,000 acre-feet would be provided with a 124-foot drawdown. Plans call for the initial installation of four units, having a total installed capacity of 1,088,000 kilowatts (plant capability of 1,240,000 kilowatts). Ultimate installation would be seven units, totaling 1,890,000 kilowatts (2,170,000 kilowatt capability). The average annual generation would be 391,000 kilowatts.

The Low Mountain Sheep reregulator included in the Pleasant Valley plan would be located at the same site as the Appaloosa reregulator and would also be of concrete gravity construction. However, the Pleasant Valley reregulator would have a maximum pool elevation of 1128. Reregulation storage of 28,000 acre-feet would be obtained with a 15-foot drawdown. Initial installed capacity would be two 175,000 kilowatt units giving a total plant capability of 400,000 kilowatts at 15 percent overload. The ultimate capacity would depend on downstream developments. Average annual generation under 2010 conditions would be about 188,000 kilowatts. (19)

Nez Perce-China Gardens Although no longer under active consideration, Nez Perce is the fourth alternative for development of the Middle Snake. The damsite is located on the Snake River at approximately river mile 186, about 2-1/2 miles below the mouth of the Salmon River. As proposed by Washington Public Power Supply System in their amended application of August 10, 1960, the reservoir would have a maximum pool elevation of 1,510 feet and provide

4,700,000 acre-feet of usable storage for power production and flood control with 213.5 feet drawdown. The reservoir at full pool would extend 63 miles up the Salmon River, 61 miles up the Snake River to the Hells Canyon tailwater, and about 10 miles upstream on the Imnaha River. The dam would be a concrete, double-curvature arch type, approximately 700 feet high with the length along the crest being about 1,950 feet, including thrust block and adjoining spillway. As proposed, the project would initially have 10 units, giving an installed capacity of about 2 million kilowatts and a maximum plant capability at 15 percent overload of 2,290,000 kilowatts. Under ultimate development, six more units would be added, giving a maximum plant capability of 3,550,000 kilowatts. Using present criteria, fewer, larger units would be used and the ultimate plant capability would be greater, on the order of 5 million kilowatts. Based on 2010 irrigation depletions, the project would generate about 957,000 kilowatts annually. Because a high dam located below the mouth of the Salmon River would block and perhaps destroy the important anadromous fish runs in the Salmon, Imnaha and Middle Snake River, the Nez Perce project has been abandoned in favor of High Mountain Sheep or alternative project located above the mouth of the Salmon River. (48)

Although not included in the license application, China Gardens would be required to fully develop the reach under this plan also. The dam would be a concrete gravity structure located at mile 172.5 and, with a normal pool elevation of 895, would develop 52.5 feet of head. Average annual generation and ultimate plant capability would be 100,000 and 325,000 kilowatts, respectively.

Salmon River The Salmon River drains an area of about 14,100 square miles of central Idaho and has an average annual runoff of about 8,100,000 acre-feet. Although the Salmon River and tributaries offer some of the greatest potential for development of hydroelectric power in the United States, the basin remains undeveloped chiefly because of objections made by fish interests on the grounds that construction of dams on the Salmon River would cause irreparable damage to the anadromous fish runs. The Wild and Scenic Rivers Act, approved by President Johnson on October 2, 1968, has designated the 237-mile main stem of the Salmon River from its confluence with the Snake River to the town of North Fork, for study for potential inclusion as a component of the National Wild and Scenic Rivers System.

Lower Canyon Project The damsite is located at river mile 0.5 on the Salmon River. The development proposed in House Document 403 consists of a rockfill type dam approximately 700 feet high, having a crest length of 2,200 feet. At normal pool elevation 1,575 feet, the reservoir would extend about 70 miles upstream to

the Freedom damsite. The project would provide 2,500,000 acre-feet of usable storage for flood control and power. Installed capacity, based upon present criteria, would be approximately 2,500,000 kilowatts. The gross head for power with tailwater at elevation 940 feet, pool elevation of China Gardens, would be 635 feet. In a system providing for maximum development of the Salmon River (including 2,300,000 acre-feet of storage at Crevice), the Lower Canyon project would generate an average of 503,000 kilowatts annually. In this system the Crevice project would provide the necessary storage regulation for power, and therefore the Lower Canyon storage would not add any appreciable generation at downstream projects. Because of the importance of the Salmon River runs of anadromous fish, it was recommended in House Document 403 that authorization and construction of Lower Canyon project be delayed pending development of adequate fish passage facilities. The site is located within the segment of the Salmon River designated for study for possible inclusion in the National Wild and Scenic Rivers System. (3, 13, 43)

Freedom Project The damsite is located on the Salmon River at mile 69.3, about 17 miles downstream from Riggins, Idaho. At normal pool elevation 1,780 feet, the effective head would range from 205 feet to 413 feet depending on the drawdown at Lower Canyon. The reservoir would extend to a point about 7 miles upstream from Riggins, Idaho, or about 6 miles downstream from the Crevice damsite. The powerplant capability (overload) under ultimate development would be approximately 800,000 kilowatts, and the average annual generation would be 162,000 kilowatts. As in the case of Lower Canyon, the Freedom project would block the important salmon runs and construction should be delayed pending development of adequate fish passage facilities. The project is located within the segment of the Salmon River designated for study for possible inclusion in the National Wild and Scenic Rivers System. (33)

Crevice Project The damsite is located at mile 99.7, about 13 miles upstream from Riggins, Idaho. As proposed in House Document 403, the dam would be a rockfill type structure providing an effective head of 725 feet. The reservoir, at normal pool elevation 2,570 feet, would extend upstream 65 miles and provide 2,300,000 acre-feet of usable storage based on 30 percent drawdown. The project would generate on the average about 435,000 kilowatts at-site and add about 20,000 kilowatts at downstream plants. On the basis of present criteria, the powerplant capability would be approximately 2,200,000 kilowatts. The project is located within the segment of the Salmon River designated for study for possible inclusion in the National Wild and Scenic Rivers System.(33)

Pahsimeroi Project The damsite is located on the Salmon River at mile 301.5 about 3 miles below the mouth of Pahsimeroi River. As reported in Senate Document 51, 84th Congress, 1st Session, the river is about 250 feet wider at low-water level. Geological conditions appear favorable for a dam 300 feet high creating a reservoir with 1,042,000 acre-feet of usable storage based upon 35 percent drawdown. This reservoir would afford almost complete regulation of Salmon River at the site, would eliminate local flood damages, reduce downstream flood damages an appreciable amount, firm up low flows for power generation at downstream plants, and make possible a power generating capability of about 125,000 kilowatts based on present criteria.(31)

Challis Project The damsite is located on the Salmon River at mile 333.3 between Challis and Clayton at river elevation 5,100 feet. As limited by the elevation of the town of Clayton, a dam 350 feet high at this site would provide about 530,000 acre-feet of gross storage capacity. Based on 35 percent drawdown, about 350,000 acre-feet of usable storage would be available for power, irrigation, and flood control. Most of the flood control benefits would accrue from the protection of the agricultural lands which intermittently border the Salmon River for 90 miles downstream. Based on present criteria, it is estimated that the powerplant capability would be approximately 125,000 kilowatts. The average annual generation would be about 25,000 kilowatts. This project should not be confused with the Challis Creek Reservoir, a small irrigation storage reservoir proposed by the Bureau of Reclamation for Challis Creek, a tributary of the Salmon River.(13, 31)

Tailholt Project The damsite is located on the South Fork Salmon River at mile 32.3 about 4 miles downstream from the mouth of Secesh River. As reported in Senate Document No. 51, 84th Congress, 1st Session, the site appears geologically sound and topographically favorable for construction of a high dam. Total storage of about 700,000 acre-feet could be obtained with a dam about 550 feet high. Based on a drawdown of 35 percent, approximately 470,000 acre-feet of usable storage would be available. Storage on South Fork would be desirable as it is a high runoff producing tributary of the Salmon River. Based on present criteria, it is estimated that the project generating capability would be approximately 250,000 kilowatts.(31)

Clearwater River The Clearwater River drains an area of about 9,600 square miles of central Idaho and has an average annual runoff of about 11,300,000 acre-feet. Except for a small existing installation at Lewiston and the Dworshak project being constructed on the North Fork of Clearwater River, the hydroelectric potential

of the subbasin is virtually undeveloped. Structural provisions have been made to permit adding three more units to the Dworshak powerplant. This would increase the project's peaking capability to 1,219,000 kilowatts. This large block of capacity would require reregulation facilities to smooth out the varying hourly discharges and provide a more uniform daily flow in the main stem of the Clearwater River.

Penny Cliffs Project The Wild and Scenic Rivers Act, signed by President Johnson on October 2, 1968, designates the Middle Fork of the Clearwater River as a component of the National Wild and Scenic Rivers System. Therefore, development of Penny Cliffs or alternatives on the Middle Fork have been foreclosed. However, a brief description of the Penny Cliffs project follows:

The damsite is located on the Middle Fork at river mile 78.9 about 4 miles upstream from its junction with the South Fork. As reported in House Document 403, topography of the site is favorable for an embankment type dam. A rockfill dam with a maximum height of 620 feet would provide a normal pool elevation 1,855 feet. Usable storage of 2,300,000 acre-feet would be available for flood control and power generation. The project would generate on the average about 223,000 kilowatts annually. Based on present criteria, ultimate plant capability would be 1 million kilowatts.(33)

Lenore The damsite is located at mile 31.1 on the Clearwater River, 2 miles upstream from Lenore, Idaho, and about 9.5 miles downstream from Ahsahka, Idaho. The reservoir with 10 feet of drawdown would provide approximately 11,000 acre-feet of pondage for power generation and reregulation of Dworshak peaking releases. At normal pool elevation 975 feet, the reservoir would extend 11 miles up the Clearwater River and up the North Fork to Dworshak Dam. The dam would have an effective height of 75 feet and would be about 1,830 feet in length. Fish passage facilities would be located on both the south and north shores. The project would generate an average of 75,000 kilowatts annually, and the ultimate plant capability, which would depend on downstream development, could be as much as 375,000 kilowatts.(34)

Peck Project This project is an alternative to the Lenore project. The damsite is located on the Clearwater River at river mile 36.0, about 5 miles upstream from Lenore damsite. At normal pool elevation 975 feet, the reservoir would extend 11 miles up the main stem Clearwater and to Dworshak Dam on the North Fork. The project would provide an effective height of only 40 feet as compared with 75 feet at Lenore. The project would generate an average of 38,000 kilowatts annually and its total ultimate plant

capability would be about 175,000 kilowatts. Fish passage facilities would be located on both shores.(31)

Agatha Project This project is an element of the plan that includes the Peck development. The damsite is located at mile 26.5 on the Clearwater River. At normal pool elevation 930 feet, the project would have an effective height of 53 feet. The reservoir would extend up the Clearwater River to Peck Dam. The project would have an ultimate plant capability of about 275,000 kilowatts and would generate an average of 58,000 kilowatts annually. Fish passage facilities would be provided on both shores. Development of Lenore project in lieu of Peck would probably foreclose development of Agatha.(31)

Myrtle Project The Myrtle Project is an element of the Peck plan. The damsite is located at mile 17.5 on the Clearwater River. At normal pool elevation 877 feet, the project would develop 66 feet of gross head. The reservoir would extend up to Agatha Dam. The project would generate an average of 71,000 kilowatts annually and have an ultimate plant capacity of about 350,000 kilowatts. Fish passage facilities would be provided.(31)

Lapwai Project This project would develop the remaining 35 feet of head between the existing Washington Water Power Company dam at Lewiston and Myrtle Dam. The damsite is located on the Clearwater River at mile 9.8. At normal pool elevation 805 feet, the project would generate an average of 38,000 kilowatts annually. The ultimate plant capability would be approximately 175,000 kilowatts. Fish passage facilities would be provided.(31)

Subregion 7, Mid Columbia

The Mid Columbia subregion consists of the area drained by the Columbia River below the mouth of the Snake River and above Bonneville Dam. The only potential hydroelectric project in this subregion is the Ninefoot Creek Project on the White Salmon River, a minor north shore tributary.

Ninefoot Creek Dam Project The Ninefoot Creek damsite is located at river mile 34.7 on the White Salmon River in Washington. Amended application for license was filed by the Public Utility District No. 1 of Klickitat County, Washington, on April 15, 1963. The project would consist of the Ninefoot Creek Diversion Dam on the White Salmon River, an 8,000-foot canal, the Green Canyon forebay reservoir on Green Canyon Creek, a 3,350-foot penstock, the Trout Creek Powerhouse on Trout Lake Creek, and a reregulating

reservoir on Trout Lake Creek. The plant would develop 904 feet of head, and the usable storage in the Green Canyon reservoir would be about 7,000 acre-feet. The powerplant would contain two 20,000 kilowatt units and would generate about 10,000 megawatts annually. (9)

Subregion 8, Lower Columbia

This subregion consists of the drainage of the Washington tributaries to the Columbia between the Grays River and Bonneville Dam and the Oregon tributaries between the Clatskanie River and St. Helens. The major tributaries in this subregion are the Lewis and Cowlitz rivers.

Table 30 - Potential Hydro Projects, Subregion 8

Project	Stream	Usable Storage (1,000 ac-ft)	Gross Head (ft.)	Average Annual Generation (Average MW)	Ultimate Plant Capability1/ (MW)
Cowlitz Falls	Cowlitz R.	Pondage	70	24	52
Muddy	Lewis R.	277	300	50	126
Meadows, Lower	Rush Cr.	Pondage	1,061	19	63
Meadows, Upper	Meadows Cr.	70	850	10	29
TOTAL		347	2,281	103	270

1/ 115 percent of installed (nameplate) capacity.

Cowlitz Falls Public Utility District No. 1 of Lewis County, Washington, has filed an application for preliminary permit for Cowlitz Falls Project. The proposed plan consists of a concrete-gravity diversion dam about 70 feet high and about 400 feet long to be located on the Cowlitz River, about 5 miles southeast of Kosmos, Washington; a reservoir providing about 3,000 acre-feet of usable storage; a concrete-lined diversion canal about 1,000 feet long; intake structure, and 150-foot long steel penstocks; and powerhouse providing total capacity of about 45,000 kilowatts.

Lewis River The Lewis River drains an area of 1,050 square miles lying between the Cascade Range on the east and Columbia River on the west. The main branch of the Lewis River has its source on the northwest slope of Mt. Adams. It flows in a south-westerly direction approximately 110 miles and joins the Columbia River at mile 87.0, about 19 miles downstream from Vancouver, Washington.

Muddy Project The project would be located on the Lewis River at mile 61. Application for license was filed by Pacific Power & Light Company on November 26, 1956. This storage project

would consist of an earthfill dam which would provide 277,000 acre-feet of usable storage at full pool elevation 1,300 feet. Maximum gross head for power generation would vary from 300 to 335 feet, depending on the pool elevation at Swift No. 1, just downstream. The powerplant would have an installed capacity of 110,000 kilowatts. Federal Power Commission action is pending on this application. This project would be operated in coordination with the company's Merwin, Yale, and Swift projects located downstream.(23)

Meadows Project The project would consist of two powerplants utilizing the flow of Rush, Curly, Meadow, and Big Creeks, tributaries of the Lewis River. Application for license was filed by Pacific Power & Light Company with the Federal Power Commission on January 28, 1959. The initial installation would consist of a diversion dam on Rush Creek and the 25,000-kilowatt Lower Drop powerhouse on the proposed Muddy Reservoir. The ultimate development would include in addition the Skookum Reservoir on Big Creek, a diversion dam on Meadow Creek, the 25,000-kilowatt Upper Drop powerhouse on Rush Creek, and an additional 30,000-kilowatt unit at the Lower Drop powerhouse. The Lower Drop would develop 1,061 feet and the Upper Drop 850 feet of gross head. Usable storage in the Skookum Reservoir would be 70,000 acre-feet. All dams will be earth and rockfill.(23)

Subregion 9, Willamette

This subregion consists of the Willamette River Basin in Oregon. A number of potential hydroelectric projects were investigated in the Willamette Basin Comprehensive Study of Water and Related Land Resources completed in 1970. One conventional hydroelectric project, the Shellrock Project, has been included as a long-range element of the Comprehensive Basin Plan. In addition, several potential pumped-storage projects have been included in the plan, and these are discussed in the pumped-storage section of this chapter. For further details of the sites investigated, reference should be made to Appendices J (Power) and M (Plan Formulation) of the Willamette Report.(25, 26)

Shellrock Project This project would be a single-purpose hydroelectric project located on the Oak Grove Fork of the Clackamas River above Lake Harriet. Water would be diverted from the Oak Grove Fork just below Timothy Lake and conveyed 4 to 5 miles downstrea in a pipeline to develop about 925 feet of head. The powerplant would have an installed capacity of 35,000 kilowatts and a peaking capability at 15 percent overload of about 40,000 kilowatts. Average annual energy would be about 12,300 megawatts. Operation of the plant would be coordinated with the existing Timothy Lake and Oak Grove projects. (9, 25, 26)

Subregion 10, Coastal

This subregion consists of all Oregon and Washington streams draining to the Pacific Ocean except for the Columbia River. Only one potential project from this subregion is included, the Eden Ridge project on the South Fork Coquille River in Oregon.

Eden Ridge Project The damsite is located on the South Fork Coquille River. Application for license was filed January 29, 1960, by Pacific Power & Light Company with the Federal Power Commission. The applicant has indicated plans to amend the application to construct the project in two stages. The first stage would include a concrete-arch or concrete-gravity dam at the Eden Ridge site with normal pool elevation 2,240 feet and a powerhouse with initial capacity of 30,000 kilowatts. The second stage would include raising the dam to provide a pool elevation of 2,340 feet, construction of Lockhart Dam about 3 miles downstream, and increasing the powerplant installation to about 90,000 kilowatts. Usable storage would be 110,000 acre-feet at Eden Ridge Reservoir and 2,600 acre-feet at Lockhart Reservoir. The average annual generation would be about 22,000 kilowatts. Power will be developed by releases from either Eden Ridge or Lockhart Reservoirs through a 12,000-foot power tunnel and 3,100-foot penstock to the powerhouse. (23, 24)

Subregion 11, Puget Sound

This subregion consists of all Washington streams draining to the Strait of Georgia, Puget Sound, and the Strait of Juan de Fuca west to the Elwha River. Included in the following discussion are a number of potential projects under active investigation. In addition, a number of lesser projects were investigated in the Comprehensive Water Resource Study of the Puget Sound.(26)

Table 31 - Potential Hydro Projects, Subregion 11

Project	Stream	Usable Storage (1,000 ac-ft)	Gross Head (ft)	Average Annual Generation (Average MW)	Ultimate Plant Capability (MW)
Lower Sauk	Sauk R.	134	210	55	110
N.Fk. Snoqualmie	Snoqualmie	93	243	7	34
N.Fk. Reregulator	Snoqualmie	Pondage	572	23	52
Sultan No. 1	Sultan R.	98	390)		(84
Sultan No. 2	Sultan R.	Pondage	398)	45	(32
Sultan No. 3	Sultan R.	Pondage	300)		(24
Pilchuck	Pilchuck R.	N.A.	150	1	4
Thunder Creek	Skagit R.	Diversion	-	15	None
TOTAL		325	2,263	146	320

North Fork Snoqualmie River Project The project would consist of an earthfill embankment about 300 feet in height from base to crest and a top length about 1,700 feet. The damsite is at river mile 11.7 on the North Fork Snoqualmie River, about 11 airline miles north and east of Snoqualmie, Washington. Normal full pool would be elevation 1,545 feet. The winter operation would call for holding the reservoir below elevation 1,509 feet from November to March of each year, thus providing 50,000 acre-feet of flood control storage. An additional 43,000 acre-feet would be reserved for power generation and low flow augmentation. The power generating installation would consist of two 13,000-kilowatt units and one 4,000-kilowatt unit for a total of 30,000 kilowatts, operating under an average gross head of 243 feet. The plant's peaking capability would be 34,500 kilowatts, and the average annual generation would be about 7,000 kilowatts. This project would be operated in conjunction with the North Fork Reregulating Dam described below.(23, 26, 40)

North Fork Reregulating Dam The reregulating damsite is located on the middle reach of the North Fork Snoqualmie River 5.8 miles downstream from the North Fork storage reservoir. The project would depend on sustained and controlled releases from the upstream dam for operation and would reregulate flows as required. The dam would be a combination earthfill and concrete-gravity structure about 1,050 feet long. Maximum height would be about 80 feet from foundation to crest. The powerhouse would be located approximately 3.5 miles downstream at river mile 2.5. An 11,000-foot long canal would convey water from the outlet works to the penstock intake. The steel penstock would be 8.5 feet in diameter and 2,000 feet long. The power generating installation would consist of one 30,000-kilowatt unit operating under a gross head of 572 feet. The plant's peaking capability would be 32,300 kilowatts, and the average annual energy production is estimated at 23,000 kilowatts.(9, 26, 40)

Sultan Project A license for the project was issued by the Federal Power Commission to Snohomish County PUD No. 1 and the city of Everett, Washington, joint licensees, effective June 1, 1961. The license authorized construction of the project in two stages. Stage 1, which has been completed, is utilized solely as a storage reservoir for the city's water supply system and consists of Culmback Dam, a rockfill dam across the Sultan River at about mile 17, and diversion facilities located approximately 6 miles downstream. The license required commencement of construction of Stage II by June of 1967, and completion by June of 1970. As originally planned, Stage II consists of several elements. The most important would entail raising Culmback Dam from its present elevation of 1,408 to elevation 1,478 to provide a reservoir with

a normal operating pool at elevation 1,450. It would also include construction of powerhouse No. 1 and pertinent facilities at Culmback Dam. A second dam would be constructed about 3-1/2 miles downstream, and an 11,500-foot-long tunnel would carry water to powerhouse No. 2, located just above the existing city of Everett diversion dam. An additional tunnel would be constructed from the diversion dam to the existing Lake Chaplain reservoir. A 10,000-foot lined power canal would carry water from Lake Chaplain to powerhouse No. 3, located on the Sultan River at river mile 6. The proposed installed capacities are as follows: Sultan No. 1, two units totaling 84,000 kilowatts; Sultan No. 2, two units totaling 32,000 kilowatts; Sultan No. 3, one unit of 24,000 kilowatts. Phase II has since been deferred, and, if constructed, may involve a somewhat different plan of development, possibly involving pumped-storage.(23)

Pilchuck River Project An application for a preliminary permit has been filed with the Federal Power Commission by the city of Snohomish, Washington. The proposed project would consist of a two-stage development. Stage I would include construction of a 50-foot high concrete-arch dam and reservoir located about 17 miles upstream from the city of Snohomish on the Pilchuck River, a water treatment plant adjacent to the dam, and a water supply conduit to the city of Snohomish. Stage II construction would include increasing the height of the dam to 150 feet, a powerhouse with installed capacity of 4,000 kilowatts, and appurtenant facilities.(26)

Thunder Creek An application for a preliminary permit has been filed with the Federal Power Commission by Seattle City Light for the Thunder Creek Diversion Project. The proposed project would consist of a thin-arch diversion dam about 185 feet high and about 450 feet long, located on Thunder Creek, a tributary of Skagit River and a 6-1/2 mile long tunnel to convey water to Ross Lake. It is estimated the power output at Ross powerplant would be increased by about 15 percent by the proposed diversion.(26)

Lower Sauk Project Contained in one of the alternate long-range plans in the Puget Sound Study, the Lower Sauk Project would be a multiple-purpose storage reservoir located at mile 5 on the Sauk River. With a pool elevation at 490 feet, 134,000 acre-feet of storage would be available for flood control, low flow augmentation, recreation, and power. Developing a head of 210 feet, the powerplant would have an installed capacity of 96,000 kilowatts (110,000 kilowatts at 15 percent overload) and would generate an average of about 55,000 kilowatts annually.(26, 27)

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COLUMBIA-NORTH PACIFIC REGION COMPREHENSIVE FRAMEWORK STUDY OF --ETC(U)
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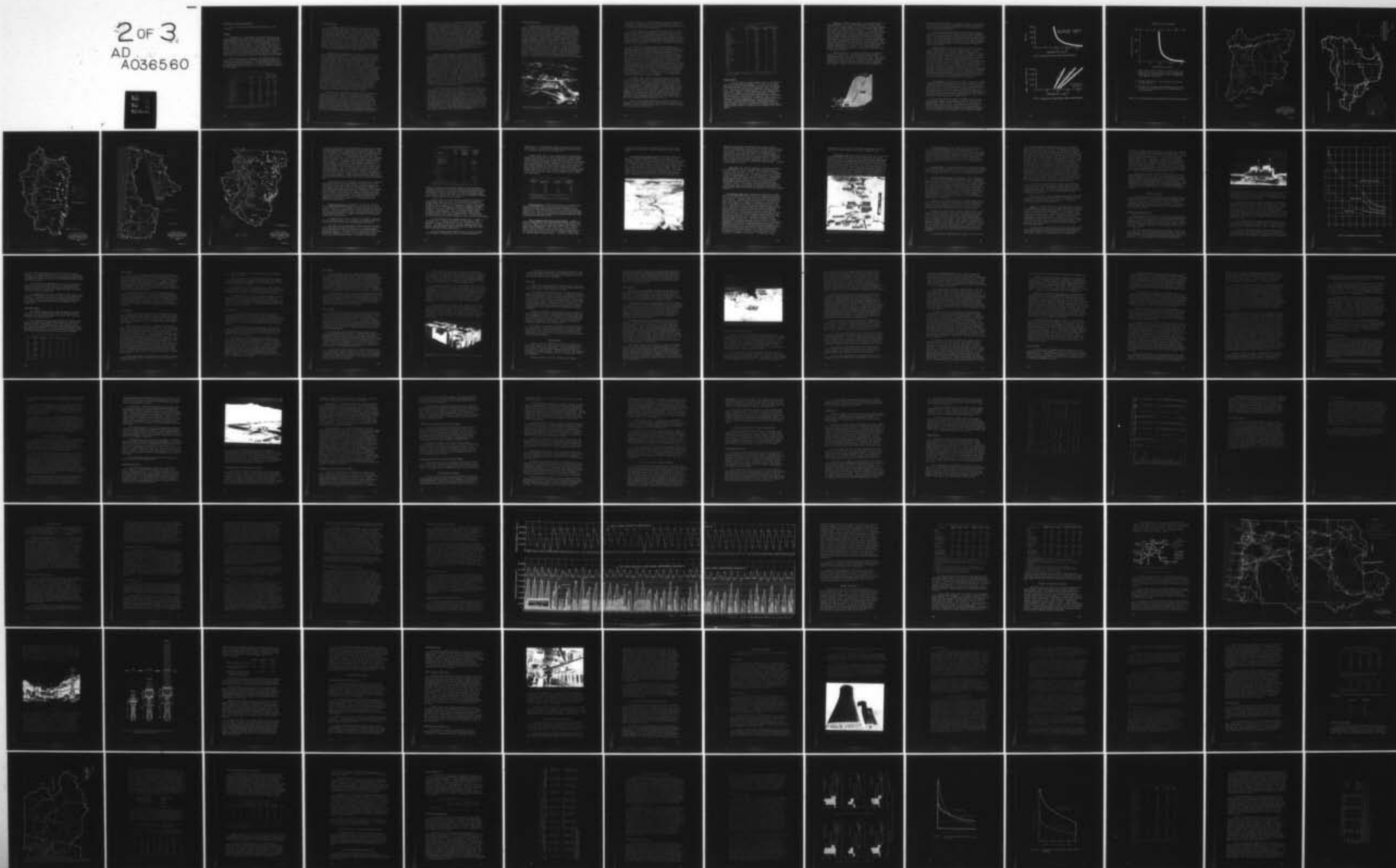


Subregion 12, Oregon Closed Basins

There are no potential hydroelectric projects in this subregion.

Summary

Throughout the Columbia-North Pacific Region there remain significant undeveloped hydroelectric resources. The forecasted power demands show that all of the hydroelectric capability which can be economically developed in the Pacific Northwest will be usable in meeting regional loads. It is possible that some of the projects listed can be developed as single-purpose power projects. However, the need for the most efficient use of our limited water resources tends to favor multiple-purpose development. Opportunities exist for developing hydroelectric power potential at storage projects which will be constructed to meet such needs as irrigation, flood control, water quality, municipal and industrial water supply.

Some of the projects discussed in this appendix have been studied in considerable detail while the information available on many other potential developments is limited, and additional study is required to determine feasibility. Table 32 summarizes the undeveloped hydroelectric potential of the various subbasins discussed in this appendix.

Table 32 - Summary of Potential Hydroelectric Projects

Subregion	Usable Storage (1,000 ac-ft)	Gross Head (ft.)	Average Annual 1/ Energy (Average MW)	Ultimate Plant Capability (MW)
1. Clark Fork-Kootenai-Spokane	4,425	2,902	558	1,929
Clark Fork	(3,725)	(2,422)	(358)	(1,454)
Kootenai	(Pondage)	(208)	(138)	(395)
Spokane	(700)	(272)	(62)	(80)
2. Upper Columbia	432	1,499	533	1,237
3. Yakima	0	0	0	0
4. Upper Snake	3,413	2,177	389	960
5. Central Snake	3,173	2,740	294	678
6. Lower Snake	11,212	4,275	2,629	12,731
"Middle Snake" 2/	(2,250)	(772)	(1,012)	(4,831)
Salmon	(6,662)	(2,735)	(1,210)	(6,000)
Clearwater	(2,300)	(768)	(407)	(1,900)
7. Mid Columbia	Pondage	904	10	40
8. Lower Columbia	347	2,281	103	270
9. Willamette	Pondage	925	12	40
10. Coastal	110	1,797	22	90
11. Puget Sound	325	2,263	146	320
12. Oregon Closed Basins	0	0	0	0
TOTAL	23,437	21,763	4,696	18,295

1/ Includes both at-site and increased generation at downstream plants.
2/ High Mountain Sheep, China Gardens, and Asotin.

Reservoir Storage

The Columbia-North Pacific Region is divided into areas of distinctly different hydrologic character, one lying west and the other east of the Cascade Range. The coastal streams to the west are relatively short and empty into the Pacific Ocean, Puget Sound, or the Lower Columbia River. On the west side, precipitation from the predominant winter storms is generally in the form of rain rather than snow, and the runoff cannot be reliably forecasted more than a few days in advance. East of the Cascades, the Columbia River drains an area in excess of a quarter million square miles where snowmelt runoff has a major effect on the annual streamflow pattern. The ability to predict runoff from the snowfed streams permits efficient management of the water resources by providing the ability to operate storage on a forecast basis.

Compatibility of Storage Use The major annual flood on the Columbia River occurs within the period from May to July and results from the melting of snow which has accumulated during the winter. During those months when the precipitation at the higher elevations is being stored as snow rather than contributing to the river's flow, the region's electric loads are highest. To obtain the required generation, the low natural flows are supplemented by releases from stored water, and thus the reservoirs which are operated for power normally reach their lowest levels before the occurrence of the May-July flood flows. Once the flood flows are stored, the reservoirs may be held full for recreational use until the storage is again required for power or other uses. Efficient storage operation for power and flood control serves also to improve conditions for navigation where open river reaches remain, by increasing depths of flow during the low natural flow months. Irrigation and low flow augmentation for pollution abatement also require the storing of floodwaters, but, unlike power and navigation, the greatest need for storage release occurs during the warm, dry summer months. Thus water stored and released for irrigation and water quality, although assisting in flood control, does not contribute as directly to increased firm capacity or usable energy.

On the west side of the Cascade Range, the major floods are caused by severe storms which occur chiefly during November, December, and January. However, the magnitude and intensity of a storm cannot always be used as an index to the resulting flood. Temperature sequence, ground-water recharge, snowpack, and other factors influence the rate as well as the volume of runoff. The regulation of the multiple-purpose reservoirs located on the west side, specifically those located in the Willamette River Basin, is normally divided into three seasons: (1) major flood season, November 1 - January 31; (2) conservation storing season, February 1 - May 31; and (3) conservation release season, June 1 - October 31.

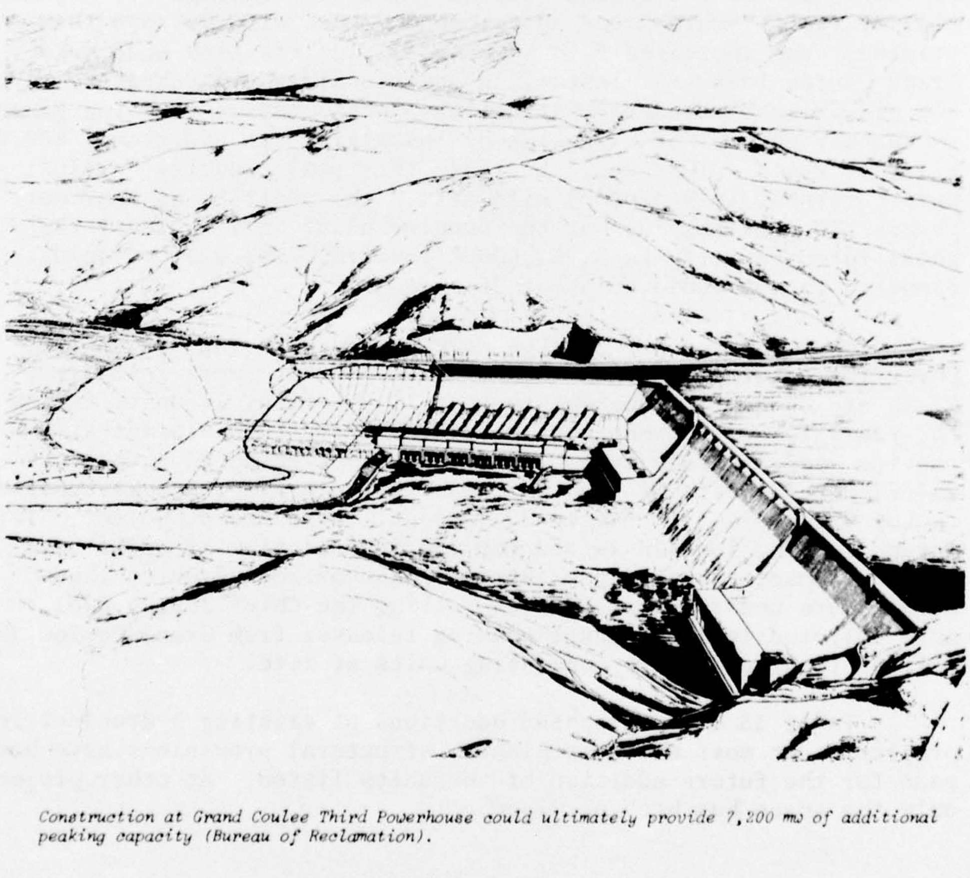
Maximum flood control space is provided during the period of maximum flood potential. During that season, the reservoirs are held evacuated to minimum flood control pool, or filled and emptied as the control and regulation of floods may require the use of the flood control storage space. During a critical water year on the Columbia River, power generation required at Willamette Basin projects to meet system firm commitments may curtail scheduled filling at some Willamette Basin reservoirs and result in partial filling of the reservoirs to the extent that there would not be enough conservation storage to meet irrigation and other high-priority requirements during the conservation release period. Should this occur, exclusive power storage and possibly dead storage in the amount that power releases curtailed the scheduled filling may be used for irrigation and other high-priority uses. This is a risk that power will assume if special regulation for power jeopardizes the normal reservoir filling.

Changes in Use of Storage The pattern of storage regulation for hydroelectric power production will change as the Pacific Northwest integrated power system progresses from a hydro base to a thermal base. During the initial stage all available power storage will be used during the adverse water years to produce the maximum possible prime power. This will establish the maximum firm load which can be carried by the system, and therefore, in years of better than minimum flow, the available storage will not be fully used for power generation. During the second stage of development, thermal generation will grow rapidly, and installations at main river hydro plants will be expanded. All available energy, including much that was formerly spilled, will become usable for replacing thermal electric energy. As much storage will be withdrawn during the winter season as can be replaced with forecasted flood season flows. As a result, the average annual use of storage will be greater than in the initial stage. During periods of adverse streamflow, all power storage necessary to meet firm loads will be used as it would be in the initial stage.

In the ultimate stage of development, reservoirs will be maintained at a relatively high level to provide full plant peaking capability until the January peak load has occurred. Following the annual peak load, storage will be withdrawn, on a forecast basis, to generate hydro energy to replace thermal energy and to prevent subsequent spill during the flood runoff season. The change from one stage to the next will be gradual, and the length of each period will depend on the rate of load growth, the rate of adding new storage and thermal generation, and the magnitude of the ultimate hydro-installed capability. The common objective in all three periods is to reduce the spill of water during the high runoff period by storing flows in excess of downstream plant hydraulic capacities and thus convert potential spill into a usable commodity.

Peaking Installations

Peaking capacity may be defined as that part of a powerplant's generating capacity which is operated during periods of highest electrical energy demand. The amount of peaking capacity to be installed in a hydroelectric plant is dependent on a number of factors, one of the most important being operating limitations, such as rate and amount of change in reservoir and tailwater elevations, that may be imposed for the protection of other water-oriented interests. Other factors include streamflows, reservoir storage and pondage capacity, and available head. In the Pacific Northwest, many hydroelectric projects are being designed and constructed with provisions included for the future installation of additional generating units when needed to serve increased loads. In some cases it may be necessary to provide reregulation facilities when the additional capacity is installed to smooth out the peaking releases and maintain safe and acceptable conditions downstream. Examples of such requirements are found at Libby and Dworshak where an open river of some extent exists downstream from each of the projects. Both the Libby and Dworshak powerplants have been designed



Construction at Grand Coulee Third Powerhouse could ultimately provide 7,200 mw of additional peaking capacity (Bureau of Reclamation).

to operate ultimately at an annual capacity factor of approximately 20 percent. In addition to the initial installations, intakes, penstocks, and substructures are now being constructed to facilitate installation of the future peaking units.

At the Columbia River and lower Snake run-of-river projects, facilities are also being included in the initial phase for the future installation of additional peaking units. However, in the interest of navigation and other water uses, the ultimate annual capacity factor of these plants has been limited to about 40 percent. This, coupled with available pondage and overlap provided at each project, results in maintaining acceptable conditions for navigation in the various reservoirs.

At Grand Coulee, construction of a third powerplant is underway. When the six 600,000-kilowatt units currently authorized are completed, the Grand Coulee project will provide a total rated capacity of 5,967,000 kilowatts including the addition of two 48,500-kilowatt pump-turbine units in the existing pumping plant. Upon completion of the Columbia River Treaty projects in Canada and the Libby Dam in the United States, the usable storage for regulation of the Columbia River above Grand Coulee will be more than tripled. The increased firm streamflow plus its high head make Grand Coulee ideal for installing additional peaking capacity beyond the six presently under construction. Consideration is being given to further powerplant expansion by installing six additional 600,000-kilowatt units. This would increase the total capacity, excluding pump-turbines, to 9,470,000 kilowatts. The addition of four more reversible pump-turbines at the pumping plant will increase the total rated capacity to 9,761,000 kilowatts. The average annual capacity factor would be about 25 percent.

At Chief Joseph, intakes were provided during the initial phase for a total of 27 units, of which 16 units were installed. Plans are currently underway to install the final 11 units during the years 1975-77. When completed, the 27-unit powerplant will provide approximately 2,069,000 kilowatts of rated capacity, and 2,482,000 kilowatts of peaking capability. Average annual capacity factor will be approximately 50 percent. Like Grand Coulee, Chief Joseph is also ideally suited for the installation of additional peaking capacity beyond the currently authorized 27-unit plant. Studies are underway considering raising the Chief Joseph pool to more efficiently accommodate peaking releases from Grand Coulee as well as to provide more generating units at site.

Table 33 lists proposed additions at existing hydroelectric projects. At most of these plants, structural provisions have been made for the future addition of the units listed. At other projects, only the space has been provided.

Table 33 - Proposed Additions to Existing Hydroelectric Projects

Project	Existing and Under Construction		Proposed Additions	
	No. Units	Total Capacity (MW)	No. Units	Total Capacity (MW)
Bonneville	10	518.4	6	480.0
John Day	16	2,160.0	4	540.0
McNary	14	980.0	6	420.0
Priest Rapids	10	788.5	6	473.1
Wanapum	10	831.2	6	498.8
Rock Island	10	212.1	6-8	350.0
Chief Joseph	16	1,024.0	11	1,045.0
Grand Coulee	23	4,070.0 1/	3	1,800.0
Grand Coulee Pumping Plant	2	97.0	4	194.0
Boundary	4	551.0	2	275.5
Noxon Rapids	4	282.9	1	70.7
Libby	4	420.0	4	420.0
Chelan	2	48.0	2	48.0
Ice Harbor	3	270.0	3	332.9
Lower Monumental	3	405.0	3	405.0
Little Goose	3	405.0	3	405.0
Lower Granite	3	405.0	3	405.0
Dworshak	3	400.0	3	660.0
Hells Canyon	3	391.5	1	130.5
Oxbow	4	190.0	1	47.5
Brownlee	4	360.4	2	180.2
Bliss	3	75.0	1	25.0
Lower Salmon	4	60.0	1	15.0
Anderson Ranch	2	27.0	1	13.5
Cougar	2	25.0	1	35.0
Merwin	3	135.0	1	45.0
Yale	2	108.0	2	108.0
Mayfield	3	121.5	1	40.5
Mossyrock	2	300.0	1	150.0
Diablo	2	120.0	2	120.0
TOTAL	174	15,781.5	91-3	9,733.2

1/ Includes rewinding all of the 18 original main units, which increases their nameplate rating to 125 MW each, and two of the three 10 MW station service units.

Source: (6, 24).

Pumped Storage

Electrical resource studies indicate that, in the future, a major part of the Pacific Northwest's base load will be met by nuclear powerplants. Nuclear plants can supply base load energy at a relatively low cost but are an expensive source of peaking power. Therefore, more economical means for providing peaking power must be sought. Studies indicate that the peaking requirements of the region will be met until about 1990, by adding generating units at existing conventional hydroelectric projects. When the addition of those units is completed, other sources of peaking power must be developed. Several alternative sources are available, including pumped-storage. Recent improvements in reversible pump-turbines have created considerable interest in pumped-storage, especially in areas where reservoir sites with high head are available, as they are in the Columbia-North Pacific Region.

Operation Pumped-storage hydro is unique among methods of power generation as it is dependent on other electrical power sources for its energy supply. It functions as an energy accumulator in that low-valued off-peak energy is stored by pumping water from a lower to a higher reservoir (figure 7). The stored water can then be returned through the turbines to generate power during peak load periods, when it is most needed and has its greatest value. Pumped-storage installations offer many of the favorable characteristics of conventional hydroelectric plants including rapid start-up, long life, dependability, low operating and maintenance costs, and adaptability as low cost spinning reserve. Due to transmission losses and inefficiencies in the operation of pump-turbines, approximately one and one-half times as much energy is required for pumping as is obtained in the generating phase. However, this increased energy use is justified by the high value of the peak generation.

Pumped-storage may be designed to operate on a seasonal, weekly, or a daily cycle. Seasonal pumped-storage would be economical only in a system where there is a period in the year in which there is both surplus water and surplus energy. The surplus energy would be used to pump the surplus water into a holding reservoir to be used for generation during periods of greatest power demand. Projects of this type are especially adaptable to

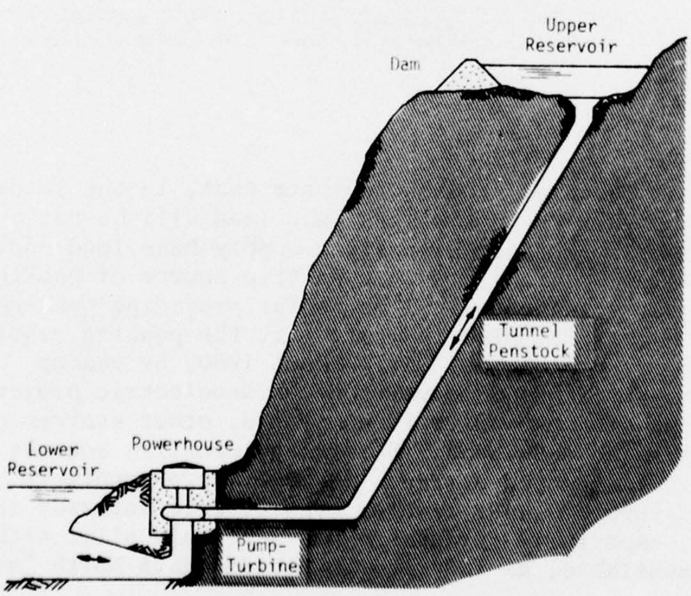


FIGURE 7. Typical Pumped Storage Project

multiple-purpose development. An example of this is the Paterson Ridge site, which is being considered as a multiple-purpose project for irrigation, recreation, thermal plant siting, and seasonal pumped-storage power generation.

Daily and weekly pumped-storage hold considerable promise, especially in light of the fact that in the near future thermal plants will begin assuming an increasing share of the region's base load. As more thermal plants are put into operation, more off-peak energy will become available for potential use by pumped-storage plants. Water would generally be pumped at night (and on weekends) and released during the day to generate energy for meeting the system's peak loads.

Pumped-storage projects are generally classified as either "pure" pumped-storage or "combined" pumped-storage. A "pure" pumped-storage project is one which operates exclusively as a pumped-storage plant. The plant's generation capability is dependent wholly on water pumped from the lower to the upper reservoir. On the other hand, a "combined" pumped-storage project is a conventional hydro project whose generating plant consists either partially or wholly of reversible pump-turbines. Water pumped from the lower pool serves only to supplement conventional reservoir inflow as a source of energy. Although a few combined projects are now being studied in the Columbia-North Pacific Region, this inventory is primarily concerned with pure pumped-storage projects. The latter are further subdivided into two categories: "independent" projects, in which both the upper and lower reservoirs are used exclusively for pumped-storage operations, and "adjacent" projects, in which the reservoir of a conventional hydro plant is used as the lower reservoir of an adjacent pumped-storage plant.

Site Inventory A map survey was made to evaluate the pumped-storage potential of the region. Due to time limitations, it was possible to survey only a portion of the region. The portion west of the Cascade Divide was selected because it contains the region's major load centers. However, it must be recognized that a very large potential exists in the eastern portion of the region as well. The eastern slopes of the Cascades in Washington, the Blue Mountains, and certain portions of the Rocky Mountains in Idaho and western Montana hold particular promise (figures 11-15).

Most of the effort was placed on locating sites for large peaking plants capable of operating on a daily or weekly cycle using off-peak thermal energy. Prerequisites for an economical pumped-storage project of this type include the availability of low cost energy for the pumping operations; favorable terrain to permit the construction of the reservoirs with minimum investment in dams, relocations, land and damages; and a location offering

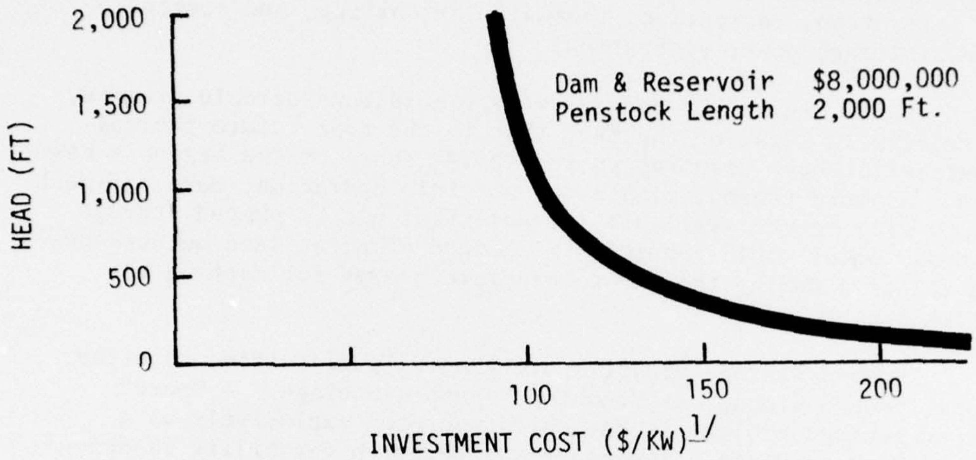


Figure 8. Investment cost vs. head for 1000 mw pumped-storage plant.

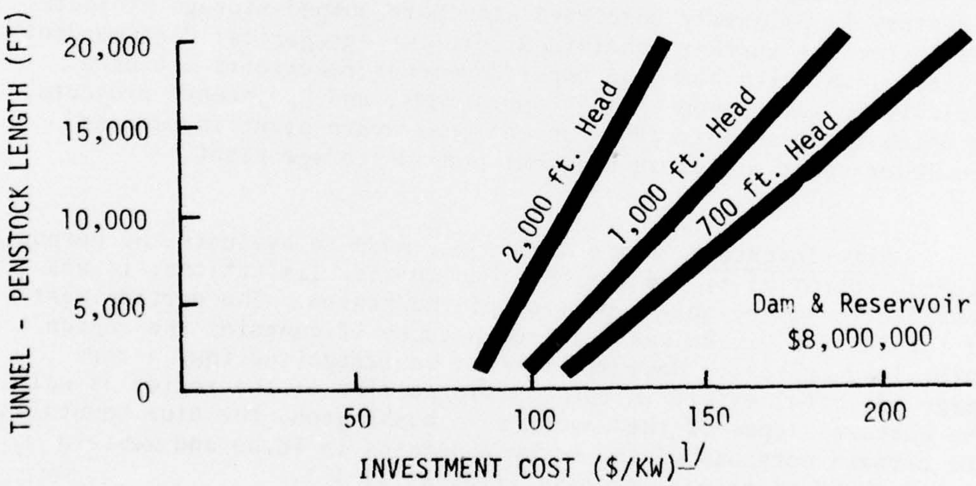
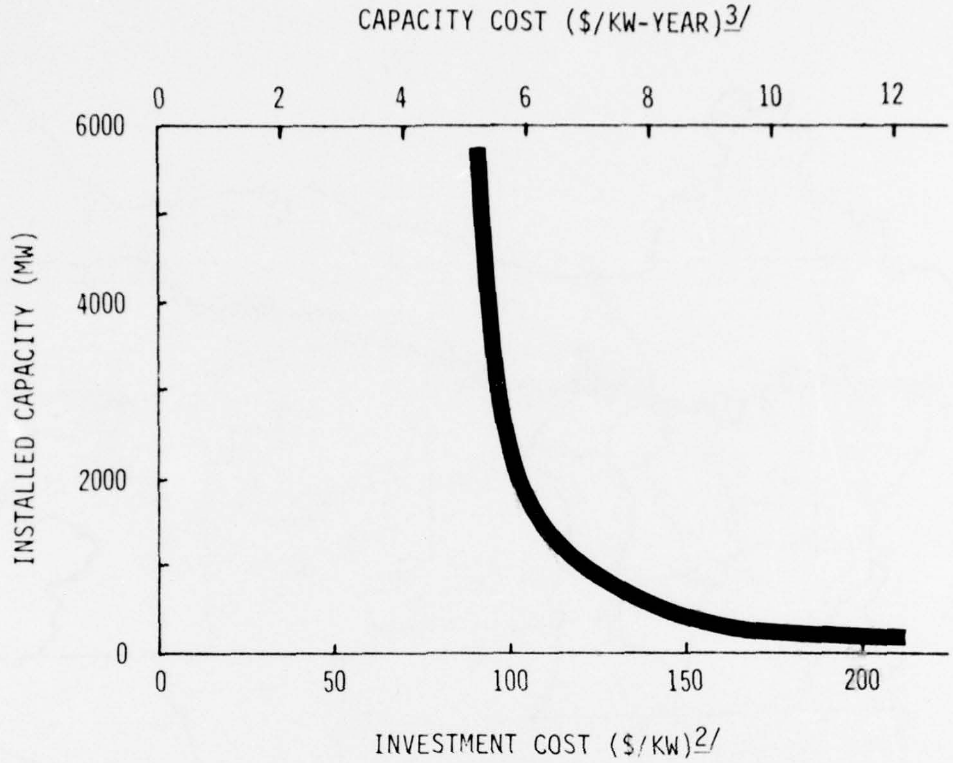


Figure 9. Investment cost vs. penstock length for 1000 mw pumped-storage plant.



1/ Plant having a head of 1500 ft., penstock length of 8,000 ft., and dam and reservoir costs ranging from $5,000,000 for a 250 MW installation to $36,000,000 for a 6000 MW installation.

2/ Includes engineering, interest during construction, and contingencies.

3/ Includes cost of amortizing investment over 50 years at 4-7/8% and estimated operation, maintenance, and replacement costs.

Figure 10. Investment and capacity cost vs. installed capacity for a typical pumped-storage plant. 1/

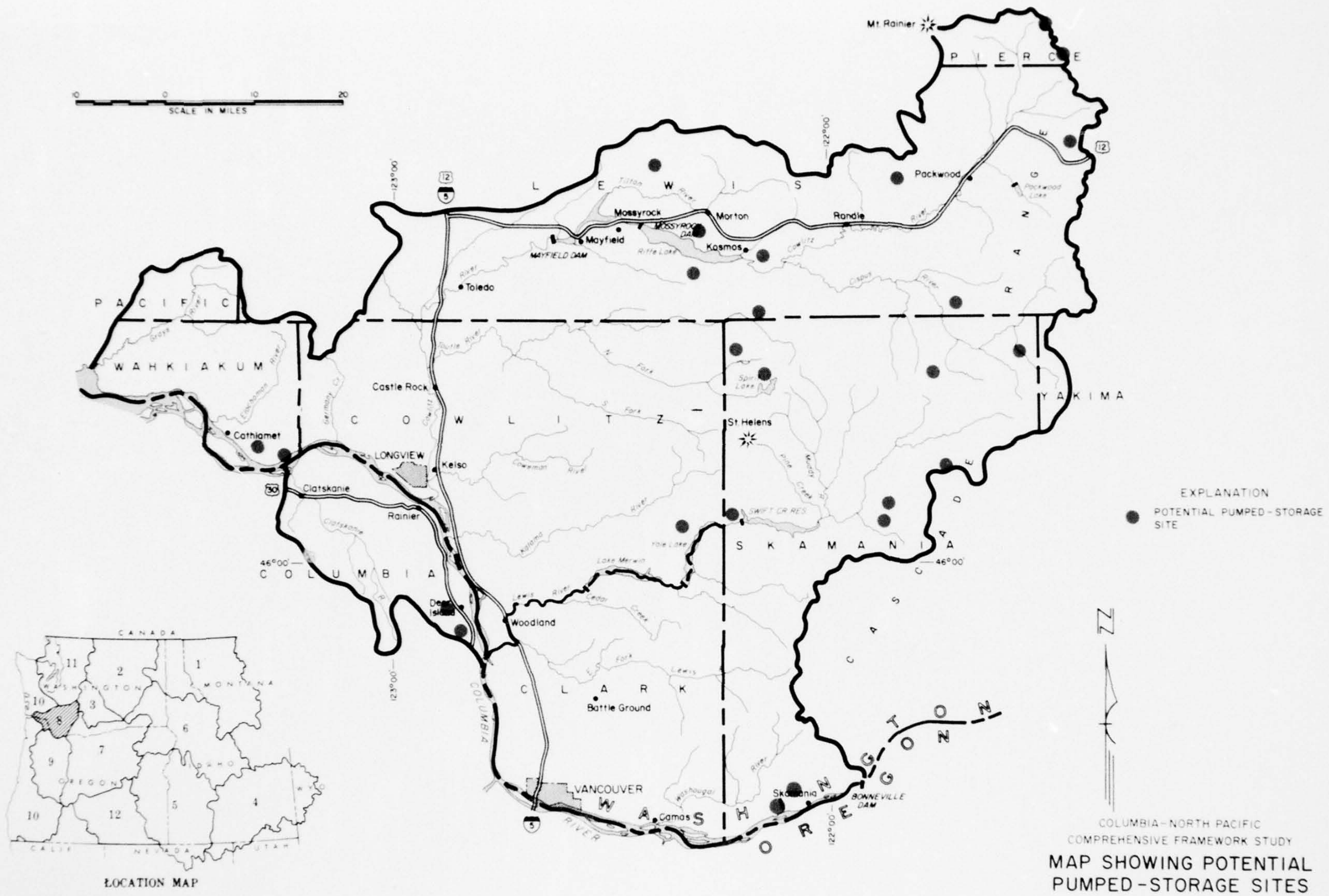
EXPLANATION

● POTENTIAL PUMPED-STORAGE SITE
MAIN STEM SITES ONLY

COLUMBIA-NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

MAP SHOWING POTENTIAL PUMPED-STORAGE SITES
MID COLUMBIA SUBREGION 7
1969

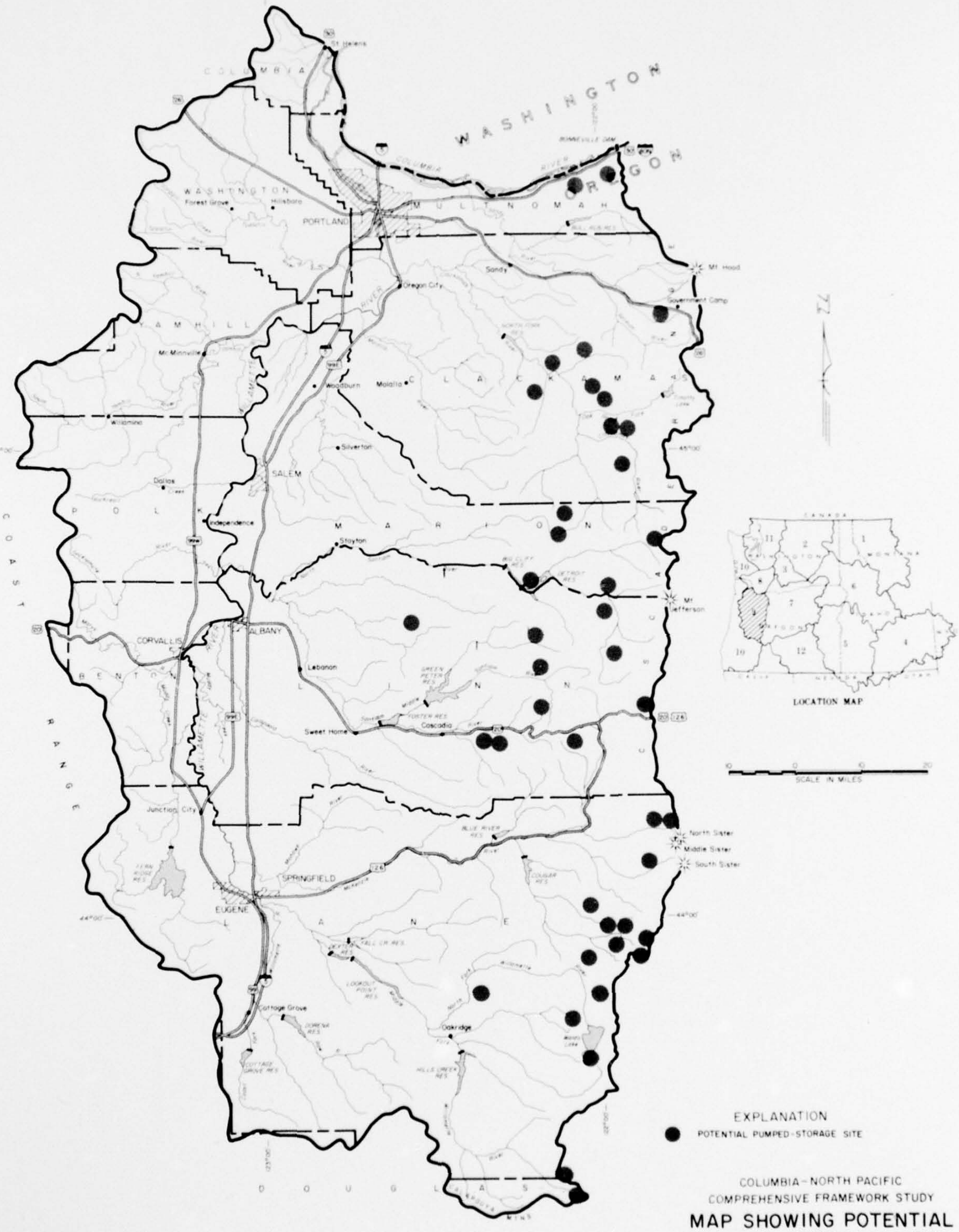
FIGURE 11



COLUMBIA-NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

MAP SHOWING POTENTIAL
PUMPED-STORAGE SITES
LOWER COLUMBIA SUBREGION 8
1969

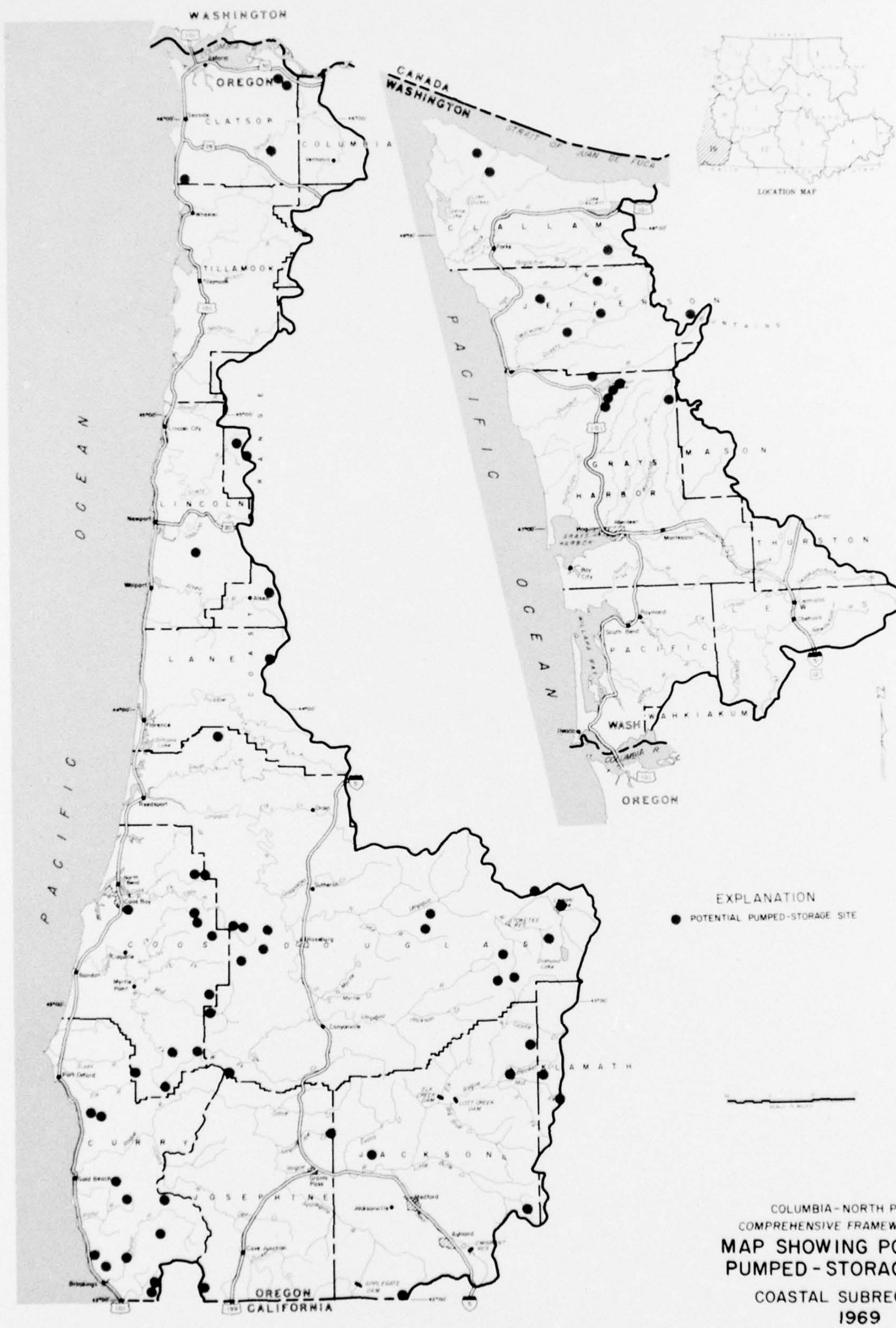
FIGURE 12



COLUMBIA-NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

MAP SHOWING POTENTIAL PUMPED-STORAGE SITES
WILLAMETTE SUBREGION 9
1969

FIGURE 13



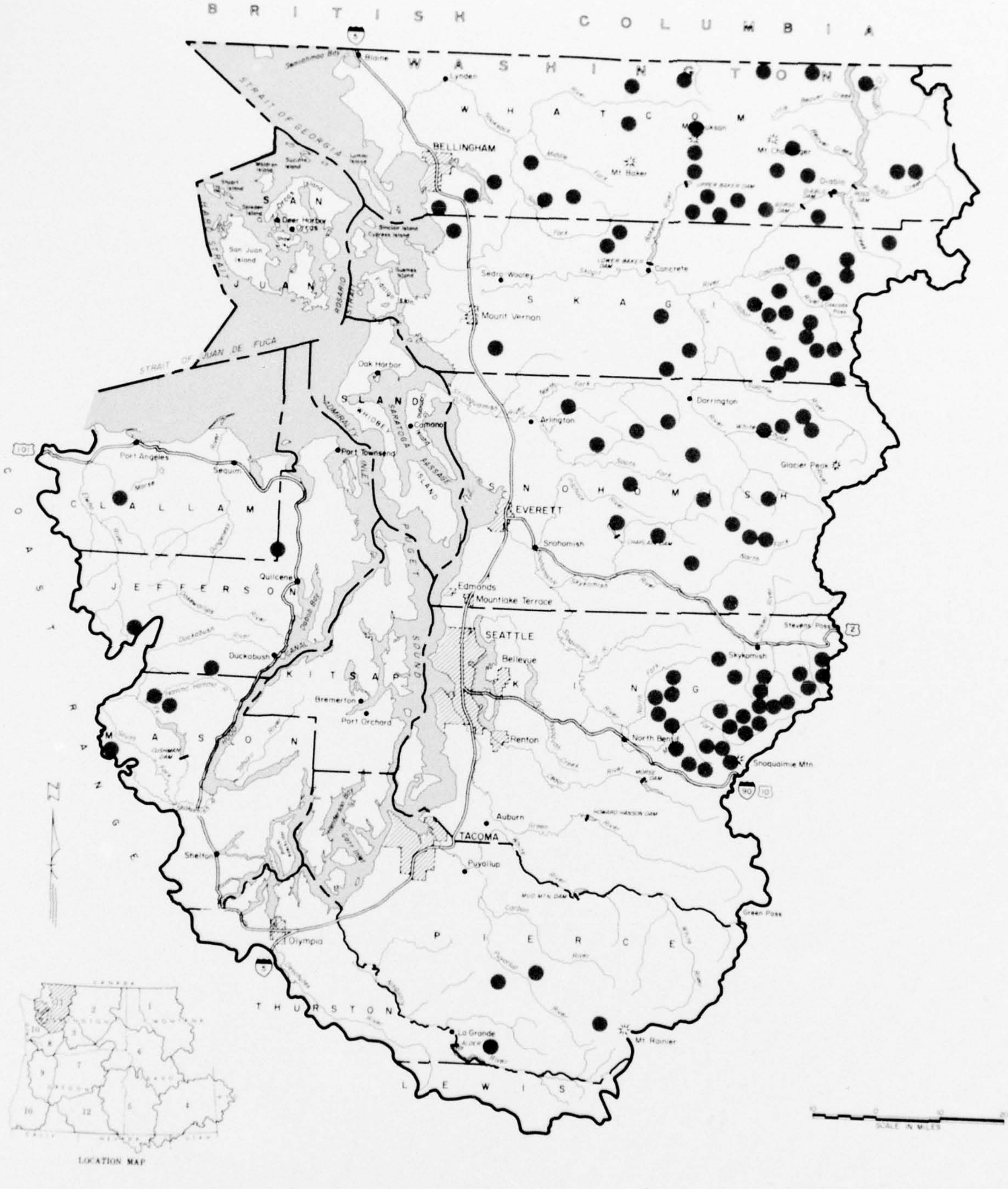
COLUMBIA-NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

MAP SHOWING POTENTIAL PUMPED-STORAGE SITES

COASTAL SUBREGION 10

1969

FIGURE 14



EXPLANATION

● POTENTIAL PUMPED STORAGE SITE

COLUMBIA-NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

MAP SHOWING POTENTIAL PUMPED-STORAGE SITES

PUGET SOUND SUBREGION II

1969

FIGURE 15

economical transmission of off-peak energy to the project for pumping and peaking energy from the project to the load centers. Also desirable from the cost standpoint are a high head (preferably 600 feet or more) and a relatively short waterway or penstock (preferably 2 miles or less). The marked effect of high heads in the reduction of unit costs is illustrated by figure 8. The cost advantage in selecting a site with a relatively short penstock tunnel is shown by figure 9. (Investment costs include a 25 percent contingency allowance, 12 percent for engineering and overhead, and interest during construction at 4-7/8 percent over 4 years). Considerable economy can be attained by going to large installations wherever possible. This is illustrated by figure 10, which shows the relationship of unit cost to installed capacity for a site typical of those located in this survey. This fact contributed to the decision to limit the inventory to sites having a capability of at least 1,000 megawatts. Another standard which was imposed was that the reservoir provide storage for at least 8 hours of operation. (41)

The inventory for the Willamette subregion is quite complete and includes data on costs and maximum site capabilities. The inventories for the Puget Sound, Coastal, and Lower Columbia subregions were made in less detail but do indicate the number of sites capable of producing at least 1,000 megawatts at an investment cost in the $80-$150 per kilowatt range. In addition, a special study was made to investigate sites capable of operating in combination with the existing Columbia River hydro projects below the confluence with the Snake River. The identified projects are summarized by subregion in table 34. All costs are based on January 1968 price levels.

Evaluation of Results Although all of the sites listed in table 34 show favorable investment costs, the inclusion of sites in this tabulation is not intended to indicate they are all feasible projects. Some are in National Parks, some in Wilderness Areas, and some may prove unacceptable for other environmental reasons. They are included here chiefly to complete the inventory of potentially economically feasible sites.

An important factor which could not be adequately evaluated in this study was geology. It is probable that further study will show some of the sites listed to be geologically unsuitable.

All of the sites listed on the Columbia River are classified as adjacent pumped-storage developments. In the remaining areas, about 5 percent of the sites are classified as adjacent pumped-storage developments. Included in the listings for the Puget Sound and Coastal subregions are five sites at tidewater which would utilize the ocean for water supply. Such plants would require

Table 34 - Summary of Potential Pumped-Storage Projects, Columbia-North Pacific Region, Subregion 7 - 11

Subregion	Number of Sites	Range of Generating Capacities (1,000 MW)	Range of Investment Costs ($/KW)
7. Middle Columbia Fig. 10			
a. Columbia River			
Bonneville Pool	9	1-8	65-130
The Dalles Pool	4	1	122-134
John Day Pool	11	1-2	92-147
McNary Pool	2	1-2	110-134
b. Other	1/	1/	1/
8. Lower Columbia (Fig. 11)	25	1+	100-150 2/
9. Willamette (Fig. 12)	42	1-10	71-145
10. Coastal (Fig. 13)			
a. Oregon	56	1+	100-150 2/
b. Washington	14	1+	100-150 2/
11. Puget Sound (Fig. 14)	108	1-10	70-150

1/ Remainder of subregion not surveyed.
2/ 1,000 MW installation only, costs for larger installations not available.

special corrosion-resistant turbine components and treatment of the upper reservoir to prevent salt-water infiltration and possible ground-water pollution. Preliminary information available at this time indicates that the additional costs for the tidewater plants will be minor. Some of the sites listed can be developed in several ways, using alternative lower reservoirs.

On the basis of the more detailed information available for the Willamette Subregion sites, it was possible to estimate the maximum capabilities of each of the sites. Of the 43 sites in the subregion, 34 are capable of a 2,000-megawatt ultimate installation, 13 are capable of 4,000 megawatts, and six are capable of 6,000 megawatts. Two sites could have an ultimate installed capacity of as much as 10,000 megawatts. The least adverse impact on the environment might result from the concentration of the greatest possible capacity at the fewest number of sites. The sites with the largest potential should accordingly be given serious consideration.

For the Willamette Basin pumped-storage sites, 7 percent of investment cost is in dams, reservoirs, and relocations. The powerhouse accounts for 38 percent of cost, and the penstocks 20 percent. The remaining 35 percent includes allowances for contingencies, engineering and design, supervision and inspection, overhead, and interest during construction.

The relationship, which should be typical of sites throughout the region, is an important factor in site selection and

optimization. It indicates that, where high-head sites are available as they are in the Pacific Northwest, the dam and reservoir is a relatively small part of the total cost.

Costs On the basis of cost studies made on the Willamette projects, it appears that it will be possible to construct pumped-storage having an annual cost of about \$9.50 per kilowatt using utility financing (25 percent private--75 percent public non-Federal). Based on current Federal Power Commission cost data, table 35 shows that pumped-storage at \$9.50 per kilowatt-year is more economical than both gas turbine and steam-electric peaking plants down to annual plant factors of about 2 percent. By way of contrast, nuclear thermal capacity, which is not a true alternative in this range of plant factors, would cost about \$22 per kilowatt-year at a 10 percent plant factor.

Table 35 - Comparison of Pumped-Storage Costs with Alternatives

Annual Plant Factor (Percent)	Pumped-Storage1/ (\$/KW-Year)	Gas Turbines2/ (\$/KW-Year)	Steam-Electric Peaking2/ (\$/KW-Year)
25	13.67	-	20.02
20	12.84	-	18.07
15	12.00	-	16.08
10	11.17	20.26	13.92
5	10.33	13.76	11.61
2-1/2	9.92	10.50	10.31
1	9.67	8.45	-

1/ Based upon capacity cost of \$9.50 KW-year and energy cost of 1.5 x 1.27 mills/KWH.

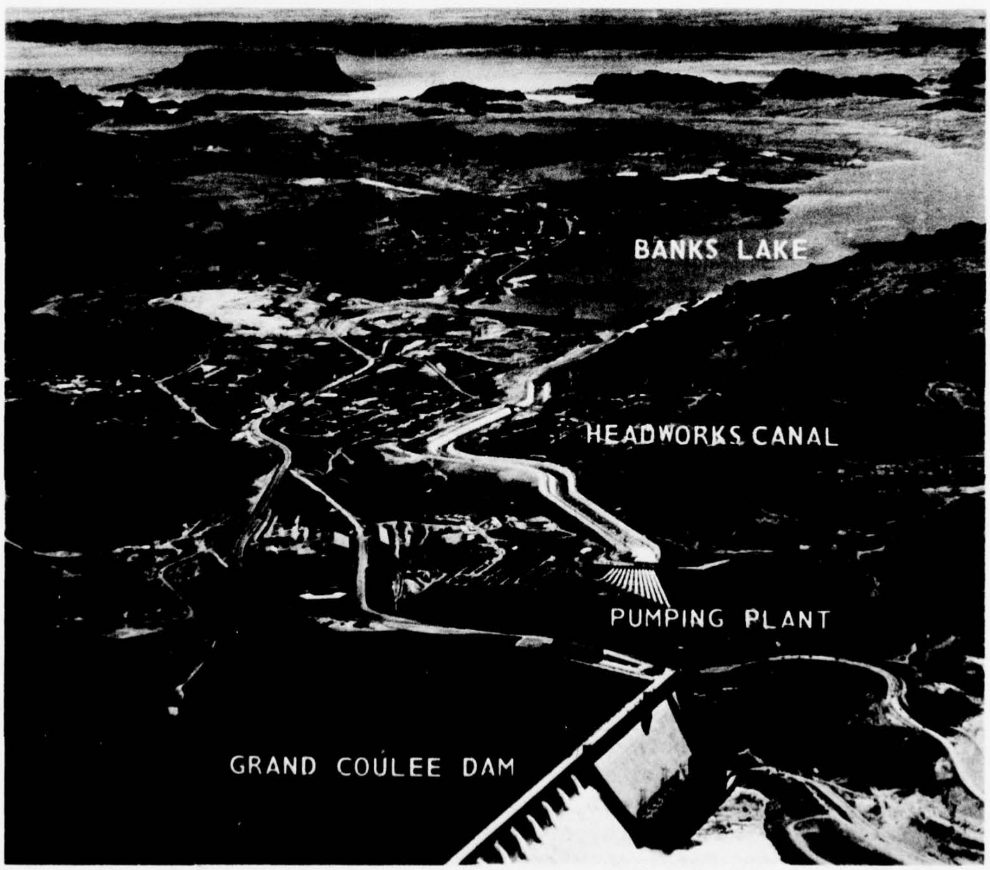
2/ Based on financing comparable to that used in computing pumped-storage costs (25 percent private - 75 percent public non-Federal).

Recreational Use Almost every reservoir is viewed by the public as a potential site for water-based recreation. It is possible that some pumped-storage reservoirs could be used for recreation, at least during that part of the year when the peaking demand is low. However, the rapid water surface fluctuations that would occur at many sites during peaking operation would make them unsuitable for recreational uses.

Sites Currently Under Detailed Investigation A number of pumped-storage projects are being studied by various agencies and utilities. Some of the sites that have received public notice are: Grand Coulee Pumping Plant, Lucky Peak, Merrill Lake, Paterson Ridge, Dirtyface Mountain, and John Day River. Two of these, Merrill Lake and Paterson Ridge, are pure pumped-storage projects located adjacent to existing reservoirs, and the remaining four are combined pumped-storage projects. In addition, studies made

by the Corps of Engineers in connection with their Clark Fork-Flathead Review Report have located 26 potential sites in that basin.

The Grand Coulee Pumping Plant was provided to pump water from the reservoir behind Grand Coulee Dam to Banks Lake, the principal irrigation storage reservoir for the Columbia Basin Project. The pumping plant was originally designed and constructed to house 12 conventional pumping units of which six have been installed to date. Under the plan to adapt the plant to pumped-storage operation, the six remaining units will be installed, in groups of two, as pump-turbines instead of conventional pumping units. These additional units will serve to increase the pumping capacity of the project during periods when secondary power and excess Columbia River streamflow are available and will also be available for



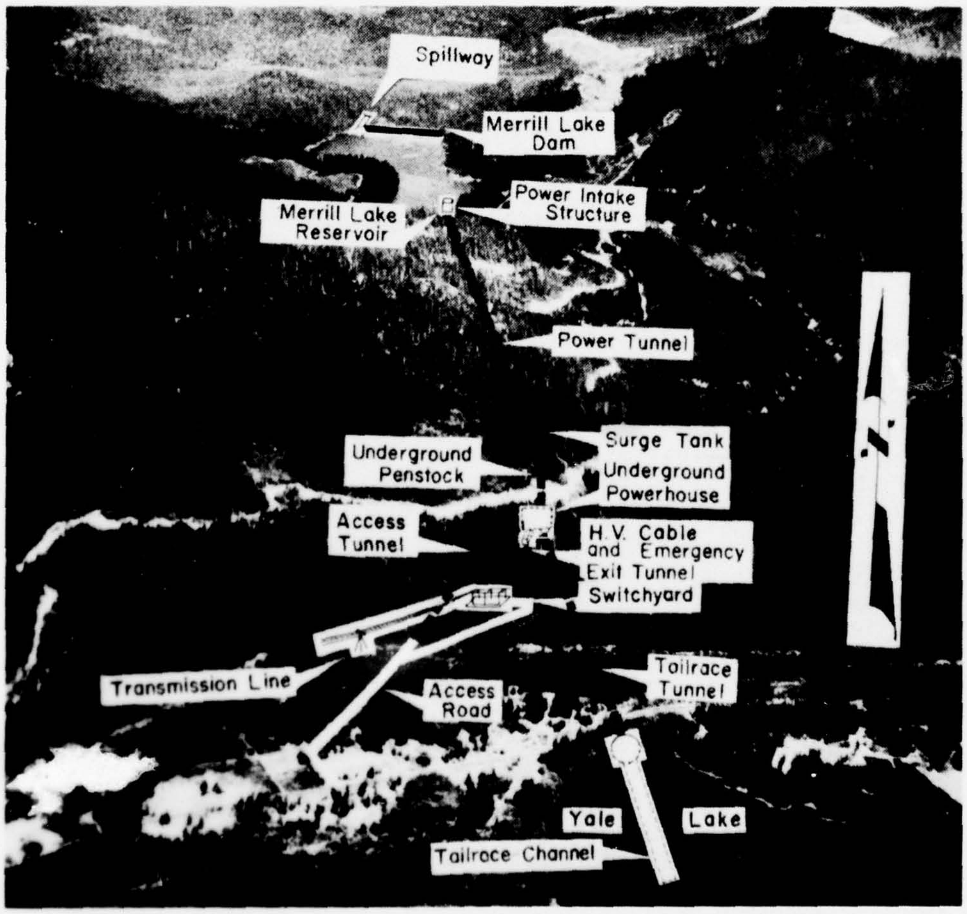
generation of peaking power during the nonirrigation season, November through March. During the latter period, Banks Lake water will be released through the pump-turbines during periods of peak power demand. Due to the large amount of storage available, operation for power generation will be quite flexible during the nonirrigation season, the main restriction being that Banks Lake must be full at the start of the irrigation season. On June 30, 1968, the Bureau of Reclamation ordered the first two 48,500-kilowatt pump-turbines for the Grand Coulee Pumping Plant. Scheduled on-line date is 1973.(22)

Lucky Peak The Corps of Engineers is studying the addition of a powerplant to the existing Lucky Peak Reservoir project, located on the Boise River in Idaho. This plant would include a 66,000-kilowatt reversible unit in addition to two 20,150-kilowatt conventional generating units. The existing Boise Diversion Dam, located 2.6 miles downstream, would be replaced by a reregulating dam having sufficient capacity to serve as the lower reservoir during pumped-storage operation as well as a reregulator for conventional hydro releases and a diversion dam for the Boise Irrigation Project. As planned, the powerplant would operate as a conventional hydro plant during the irrigation season and as a pumped-storage plant from November through March on a daily or weekly cycle.(17)

The Paterson Ridge pumped storage site (also known as Glade Creek) is located on the north side of the Columbia River about 20 miles below McNary Dam and would utilize the John Day Reservoir as its lower pool. Although having a relatively low head (about 300 feet), the site offers a large storage capacity (3 million acre-feet) which suggests development as a multiple-use project. The U.S.D.I. Geological Survey prepared a preliminary report on the site in 1967, and has recently completed a geologic study provided for by cooperative agreement between the State of Washington, Benton and Klickitat County Public Utility Districts and the Geological Survey. The Benton and Klickitat County Public Utility Districts are assisting an organization of local landowners, the Horse Heaven Irrigators, Inc., a nonprofit organization which was recently formed to consider the possible development of the Paterson Ridge reservoir site. The Utility Districts and the Corporation have engaged Washington State University to conduct a comprehensive study of the irrigation potential of the area and the suitability of the project for multiple-purpose development. Included in the study is the possibility of siting a thermal generating plant on the reservoir and using the heated cooling water effluent for agricultural purposes. The program also includes environmental, economic, and other feasibility studies and is scheduled for completion in late 1970. In addition, a brief,

reconnaissance-type study of the Paterson Ridge project has been made by the Pacific Northwest River Basins Commission. (45)

The Merrill Lake site is located just off the Lewis River near Cougar, Washington. Preliminary plans developed by the Cowlitz County Public Utility District call for installing two 250-megawatt reversible units in an underground powerhouse to develop the 1,000 feet of head between Merrill Lake and the existing Yale Reservoir. Operation would be on a daily/weekly cycle basis. On June 18, 1968, the Federal Power Commission issued a 2-year preliminary permit to the PUD for the project. After conducting preliminary studies, the PUD elected to let the permit expire due to opposition from conservationists and the fact that the peaking power generated by the project will not be needed for some time. It is possible that the PUD might take further action in the future, however. (7, 22)



Merrill Lake, a potential pumped-storage project off Yale Reservoir in Southwestern Washington (Cowlitz County PUD).

Dirtyface Mountain Chelan County Public Utility District No. 1 has proposed including reversible pump-turbines in the Dirtyface Mountain powerhouse, a part of the Wenatchee River Project now being considered for licensing by the Federal Power Commission. Two reversible units having a combined nameplate capacity of 65,000 kilowatts would be installed, along with a single conventional turbine. The project would utilize the 672 feet of head existing between a proposed reservoir on the Chiwawa River and Wenatchee Lake.(22)

John Day River The Corps of Engineers has made a preliminary examination of potential pumped-storage on the John Day River, Oregon. Results indicate there are two sites which warrant further consideration, Emigrant and Mikkalo. Studies are continuing on these.(22)

Effect of Pumped-Storage on Streamflow A high percentage of the sites located in this survey would be developed as independent projects; the reservoirs would be comparatively small and would be used exclusively for pumped-storage operations. The large, irregular flows associated with peaking operations would occur only between the upper and lower reservoirs. Once filled, only a comparatively small amount of inflow would be required to make up leakage and evaporation losses. For the most part inflows would be passed, and the operation of the project would have very little effect on the flows downstream. In some cases, however, reservoir drawdown, would be quite severe and therefore public access to the reservoirs would have to be restricted.

Other sites are located adjacent to existing storage reservoirs. Here too, operation of the pumped-storage plant would have very little effect on downstream flows, but special care would have to be taken in developing the project to insure that it does not adversely affect the functions of the existing reservoir.

A number of excellent sites suitable for daily/weekly cycle operation have been located adjacent to the Columbia River reservoirs below the confluence of the Snake. Pondage at these reservoirs is limited, and the operation of adjacent pumped-storage projects would have a major effect on the flows in the reaches of the river adjacent to the plants. While a pumped-storage plant is pumping, at night or on weekends, large quantities of water will be diverted from the existing mainstem reservoir. Conversely, at the time of peaking operation, large quantities of water will be discharged into the pool from the adjacent pumped-storage reservoir simultaneously with a peak inflow from the next mainstem project upstream.

To illustrate the magnitude of the problem, if three of the

four identified pumped-storage projects adjacent to The Dalles reservoir were developed, a total of 31,000 acre-feet would be pumped from The Dalles pool at night. Maintaining river outflow equal to inflow, The Dalles pool would be lowered 3 feet during this period. When generating at peak capacity, about 46,000 cubic feet per second, in addition to the 440,000 cubic feet per second from John Day, would be discharged into The Dalles reservoir. The hydraulic capacity at The Dalles is 366,000 cubic feet per second. Therefore, The Dalles would be storing 10,000 acre-feet per hour, or approximately 1 foot per hour. Aside from the problems of maintaining a downstream flow in the Columbia River satisfactory for the migration of anadromous fish, the 5-foot drawdown limitation at The Dalles will obviously restrict the amount of adjacent pumped-storage development. The selection of adjacent pumped-storage projects on the mainstem Columbia River must be based on determining the combination of conventional and pumped-storage units which produces the greatest net benefit in keeping with the physical and environmental limitations. This determination can be made only after an extensive study of project economics, system peaking and pondage requirements, and environmental goals.

If the adjacent pumped-storage reservoir has sufficient storage to permit seasonal operation, certain nonpower benefits could also be realized. Pumping during flood flows could help reduce downstream stages and releases for power generation during periods of low runoff could increase downstream flows, thus benefiting water quality.

The operation of a combined pumped-storage plant could have a significant effect on downstream flows, but normally the lower reservoir has sufficient capacity to serve as a reregulator, maintaining acceptable flows downstream.

Summary It appears from this survey that there is considerable pumped storage potential in the Columbia-North Pacific Region. In western Oregon and Washington alone there are nearly 300 sites worthy of consideration for development as 1,000 megawatt daily/weekly cycle peaking plants. Some of these sites possibly could be developed up to 10,000 megawatts. Although seasonal and combined pumped-storage plants were not included in this survey, indications are that there are also a few seasonal pumped-storage sites available and a number of conventional hydro projects (existing as well as proposed) which could be developed as combined pumped-storage plants.

At the presently projected rate of power development, supplemental peaking capacity beyond that available for development at conventional hydro projects will probably not be required until after 1990. However, as thermal plants are developed, the

inexpensive off-peak energy which will be available may encourage the early development of some pumped-storage before 1990. An indication of the current interest in this is the fact that reversible units are now being installed at an existing project and that detailed studies are now underway on at least five additional pumped-storage sites. Furthermore, studies may show that pumped-storage would be more economical than some of the conventional hydro units currently scheduled to carry the additional peaking loads developing prior to 1990. For example, it may be found that it would be more economical to utilize the limited storage in The Dalles pool for pumped-storage operation rather than for handling the releases from the proposed John Day units #17-20.

Studies are now being conducted to determine when and how pumped-storage will best fit into the regional load curve. These studies should also give an indication as to the type and number of plants which will be required by the years 2000 and 2020. More studies will be required to determine the relative desirability of individual sites and the effects that the operation of these plants will have on their environment, but it is evident that pumped-storage offers considerable promise as a source of future peaking capacity.

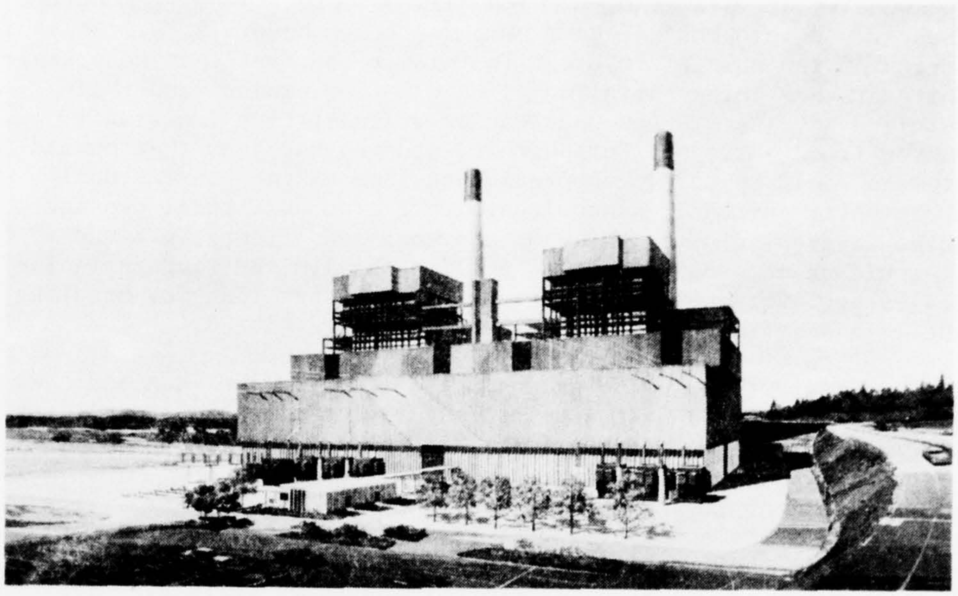
Fossil-Fuel Plants

Fossil fuel-burning steam-electric plants generate over 80 percent of all electric energy produced in the United States today. In the early days of the electric power industry, hydroelectric generation accounted for about half the total but, by 1920, the steam power share had increased to 70 percent and, since then, has gradually grown until now better than 4 out of 5 kilowatt-hours are fossil-fuel generated.

Modern Plant Characteristics

The improvement in efficiency, reliability, and availability of steam plants has been steady since the beginning power production in 1882. It has been particularly rapid during the last 25 years. Steam plants have the advantage that they can burn several different kinds of fuel and can operate a few hours per day, month, or year, or almost continuously regardless of the incidence of very low or very high rainfall.

The first steam-driven prime movers employed in power generation were slow speed, reciprocating Corliss engines no larger than 2500 horsepower. The invention and development of the steam turbine ended this restriction and permitted much greater output from a single unit. The development of steam boilers lagged behind



Centralia coal-fired, thermal-electric plant is scheduled for first generation in September 1971 (Pacific Power & Light Co.).

steam-turbine development for a time but the demand for ever greater steam flows to drive larger size turbo-generators provided the impetus for betterment of boiler design. Improvements in boilers and turbine design resulted in unit-type steam generating plants that are now the rule in the industry.

These developments and concomitant advances in metallurgy and water treatment permitted greatly increased pressures and temperatures resulting in higher outputs, lower heat rates, and unit costs. Today's steam plants, a product of these developments, have single units of as high as 1 million kilowatts capacity, critical pressure boilers operating at over 3,500 pounds per square inch, steam temperatures of 1,000°F. with double reheat to as high as 1,050°F. Higher pressures and temperatures are possible and are used for at least one existing unit, but these are the present practical maximums.

These improvements have enabled lowering of station heat rates (heat content in British thermal units of fuel required for generation of 1 kilowatt-hour) of both the best plants and the average of all steam-electric plants. This is shown by figure 16.

The 41-year period 1925-1966 has seen reduction of the "best plant" heat rate from 15,000 Btu/kwh (British thermal units per kilowatt-hour) to 8,691 Btu/kwh, an improvement of 42 percent. There has been a small slippage or retrogression in best plant heat

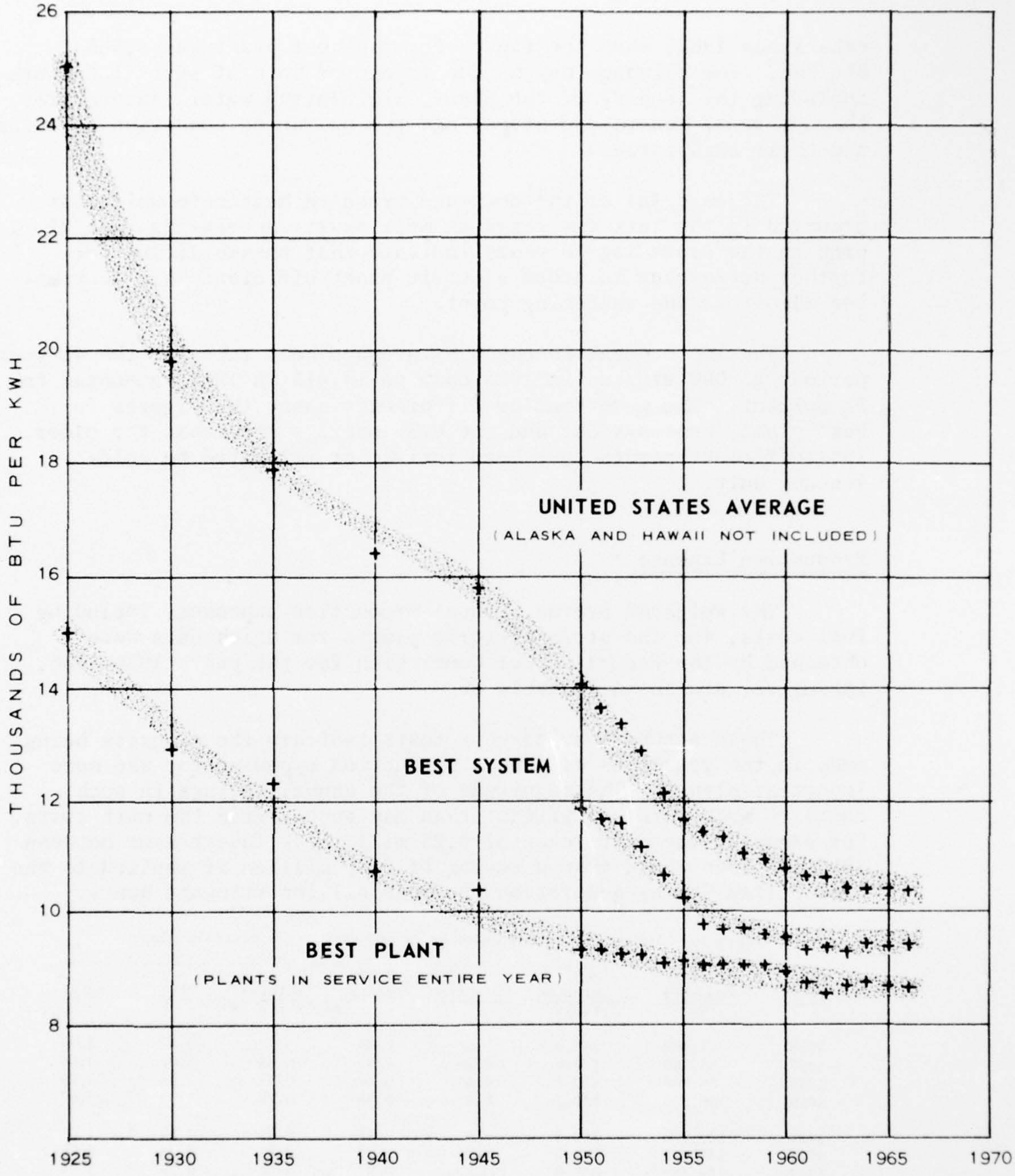


Figure 16. Steam-Electric Generating Plants – Net Heat Rates

rate since 1962, when the figure for the best plant was 8,588 Btu/kwh. The slippage may be due to one or more of several factors including the loading of the plant, circulating water temperatures, the number of starts and stops, and the operating condition of units and their auxiliaries.

The reversal of the downward trend in heat rate which has occurred in the last few years as well as its decreasing rate of drop in the preceding 10 years indicate that possibilities for further betterment in steam-electric plant efficiency are decreasing almost to the vanishing point.

The improvement in the U.S. average heat rate for the 41-year period, 25,000 Btu/kwh in 1925 down to 10,415 in 1966, amounted to 58 percent. The much smaller differences among the figures for best plant, best system, and the U.S. average show that the older, less efficient plants have been retired or relegated to cold-standby duty.

Production Expense

The weighted average annual production expenses, including fuel costs, for the steam-electric plants for which data were obtained by the Federal Power Commission for the years 1956-1966, inclusive, are shown in table 36.

These actual year-to-year costs indicate the progress being made in the reduction of annual production expenses for the more important plants. The magnitude of the annual savings in such costs is much more significant than may appear from the unit costs. For example, the difference of 0.25 mill per kilowatt-hour between 1961 and 1966 would mean a saving of $199 million if applied to the 1965 United States generation of 796.9 billion kilowatt hours.

Table 36 - Annual Production Expenses of Selected Steam-electric Plants

Year	Capacity Reported (MW)	Net Generation (TWH) 1/	Operation	Maintenance	Subtotal	Fuel	Total
			(Mills per KWH)				
1956	81,700	446.0	0.48	0.39	0.87	2.87	3.74
1957	88,700	470.6	0.49	0.39	0.88	3.02	3.90
1958	98,600	470.7	0.51	0.40	0.91	2.94	3.85
1959	109,500	532.2	0.47	0.38	0.85	2.82	3.67
1960	120,100	566.5	0.47	0.38	0.85	2.81	3.66
1961	131,600	599.5	0.44	0.37	0.81	2.78	3.59
1962	139,200	636.0	0.42	0.37	0.79	2.75	3.54
1963	147,000	695.5	0.40	0.35	0.75	2.66	3.41
1964	157,300	752.2	0.38	0.36	0.74	2.64	3.38
1965	165,600	796.9	0.38	0.37	0.75	2.60	3.35
1966	177,500	897.8	0.37	0.36	0.73	2.61	3.34

1/ 10^{12} watt-hours.

Plant Location

One of the most challenging problems which repeatedly faces each principal electric utility is that of deciding where to locate the next large generating station so as to provide the desired increment of power supply at the lowest cost. Factors considered include fuel supply, distribution of load, load growth, existing and prospective patterns of loading of the transmission system, interconnections with other systems, availability of land, foundation conditions, availability of cooling water, growing concern with thermal and air pollution problems.

The number of good sites available for large generating stations is decreasing with the increase in population, expansion of the economy, and the more active interest of the general public as well as the state and local public agencies in community matters, including thermal and air pollution. It is in the best interests of the electric utilities and their customers to use each site selected for the largest generating plant that can be economically justified.

Cooling Water

Steam-electric generating stations are located where there can be provided an adequate supply of water to condense the steam leaving the turbines. The amount of cooling water required depends upon the size of the plant, its efficiency or heat rate, and the permissible temperature rise of the cooling water passing through the condenser.

There are ways to make up for a shortage of cooling water, namely by recirculating the water in reservoirs, ponds, or cooling towers--both evaporative and nonevaporative. Each of these methods requires the supply of make-up water to replace that which is evaporated and otherwise lost. Cooling reservoirs and ponds require make-up water equal to about one or two hundredths of a cubic foot per second for each megawatt of plant capacity. Evaporative cooling towers require about two hundredths of a cubic foot per second and nonevaporative cooling towers about two thousandths of a cubic foot per second, per megawatt of plant capacity. Thus, for a 4,000-megawatt steam electric generating station, the water requirement for a cooling pond would be 40 to 80 cubic feet per second, for an evaporative cooling tower system 80 cubic feet per second, but for a nonevaporative cooling tower system only about 8 cubic feet per second. Make-up water is obtained from surface or groundwater sources.

When an ample supply of cooling water is available, the once-through circulation method for condenser cooling usually has the lowest overall cost.

The recirculation system involving reservoirs and ponds ranks next in economy.

There are two kinds of evaporative cooling tower systems--the induced-draft type and the natural-draft type. The induced-draft type usually has a slightly lower overall annual cost for generally comparable situations.

There are three types of nonevaporative cooling systems--the natural draft dry tower, induced-draft dry tower, and mechanical draft, fin-tube exchangers. The dry type systems are in the developmental stages and it is still too early to forecast costs.

The additional capital cost of a plant requiring a cooling tower system may be roughly estimated at $5 per kilowatt as compared with a similar installation utilizing conventional river water for the plant condenser. The burden of capacity reductions and increased fuel costs due to reduced efficiency may effectively double or triple this figure.

Air Pollution

In locating large generating stations, special study is required of atmospheric conditions in the area, geographical surroundings such as hills and bodies of water, the sulphur content of the fuel burned, the type of combustion and air cleaning equipment with which the station will be equipped, and the degree to which the area is developed, including other nearby air polluting sources.

Even with suitable modern furnace design, efficient dust collectors, proper plant layout and stack height, and under the meteorological conditions found at a particular plant site, the tolerable level of air pollution may in some instances tend to limit the size of the station.

Expenditures for air cleaning equipment and extra-high stacks cost from $5 to $10 per kilowatt for coal-fired plants. If the location of large generating stations is not to be severely limited, very high stacks are a necessity. Such stacks introduce cost increases from about 70 cents to $3 per kilowatt, invite objections because of possible hazards to air traffic, and face structural challenges because of sulphur corrosion problems. Thermal plants constructed for peaking purposes, either gas turbines or Diesel-powered units, contribute to air pollution. Their acceptability is enhanced only by the smaller size of such units as compared to large plants.

Ash Disposal

Coal-fired plants have the problem of ash disposal which is becoming increasingly difficult, especially in metropolitan areas, and it may be a minor economic factor to be weighed in plant location. Ash transportation costs must be considered. Usually, in thinly populated areas ash disposal can be accomplished by filling in nearby ground depressions or by depositing it on flat areas to significant height and later covering by earth overlay so as to create new more elevated land areas. For the Centralia thermal plant which is currently under construction, ash will be returned to the mine and buried where the coal excavation area is backfilled.

Millions of tons of fly ash are collected annually from steam-electric plants burning pulverized coal. The disposal of this waste material is costly, so efforts have been made to alleviate this economic loss through use of fly ash in the manufacture of portland cement, stabilization of soils, and as an admixture in concrete. These applications utilize large quantities of fly ash but the total use is only a small part of the supply.

Type of Plant

Electric power generating plants constructed in the Pacific Northwest for many years had been exclusively hydroelectric until 1966, when the Hanford nuclear plant was placed in service. This is only the first of many thermal generating plants which the growing loads of the region will require. The energy component of the load within the next 10 or 15 years is expected to exceed the output of all existing and remaining economically feasible hydro developments, thus making thermal plants a necessity. Fossil-fuel burning powerplants will then be among the economic power supply additions of the region.

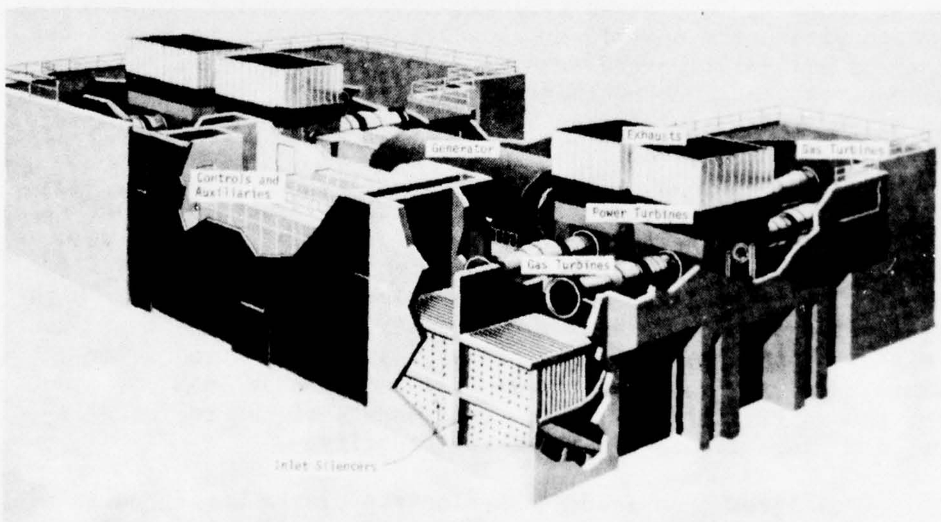
The Centralia coal field in Washington provides a fuel source for major generating stations. In Montana and Wyoming near the eastern borders of the region are other large coal fields. Economically feasible coal-fired powerplants might be either high-efficiency base load plants or low-capital cost-peaking type plants of higher heat rate. Indications are that the first need for thermal capacity in the Northwest will be for base load power but later the rapidly growing power requirements of the region will provide a place for low-cost peaking capacity.

Coal-fired base-load steam-electric plants having units of 750-1,000 megawatts capacity could, until recently, be constructed for about $110 per kilowatt to $120 per kilowatt. Plants designed to operate at comparatively low annual capacity factors (peaking plants) can be built for considerably less, perhaps as low as $80 per kilowatt to $90 per kilowatt.

Other kinds of peaking capacity such as gas turbines or Diesel engine driven generators are advantageous in some instances. The open-cycle gas turbine is made up of three principal components: an axial flow air compressor, a combustion system, and a turbine. These comprise the prime-mover section of a gas-turbine generator unit. Gas turbines can be designed to operate efficiently burning natural gas, distillate oil, or certain residual oils.

Gas-turbine generators possess many features which make them desirable for certain types of power system duty. They have a low installed cost, quick start-up, require few auxiliaries, can be made semiautomatic in starting and stopping, thus minimizing need for attention from operating personnel. They can be located with considerable freedom since their cooling water requirements are small and they are not dependent on any single fuel source. Because of simple, compact construction with all parts readily accessible, maintenance costs are low under the typical low plant factor operation.

Diesel-engine driven generators have advantages where quick starting, dependability, and minimum need for supervision by operators are of primary advantage. This makes them desirable for remotely controlled, emergency type operation or for service in "end-of-line" parts of a power system during peak load periods when the voltage in such a section would otherwise sag badly. They are commonly used as the entire source of power for small, isolated power systems.



A typical gas turbine peaking installation with eight paired units driving a 120/160 mw generator (Worthington Corp.).

Both of these latter types (gas turbines and Diesels) are in some applications preferable to steam peaking capacity. Both have the advantage of short lead-time, low-capital cost, and a much smaller cooling water requirement.

Fuel Costs

Fuel costs are of importance to thermal plants, much more so to plants to be operated base-load than to peaking plants which require much smaller annual quantities of fuel.

The location of generating stations is affected in various degrees by availability and cost of fuel. An adequate quantity of fuel of desired quality and an economical delivered fuel cost are basic to a decision as to where a large generating station is to be constructed. With respect to mine-mouth plants, the magnitude of fuel reserves within a radius of several miles has to be sufficiently large to merit consideration for such a plant location. The mine-mouth plant must be compared with possible alternatives to determine the most economical plan of development of thermal resources.

Chehalis, Washington, sub-bituminous coal is estimated to cost less than 20 cents per million Btu when produced in the quantities demanded by a 1,000 - 1,500-megawatt base-load steam plant. This projected coal cost would be higher for a peaking plant operating at a low annual capacity factor. Availability of natural gas for powerplant fuel seems doubtful although some might be obtainable outside the winter heating season.

Oil for use in any type of powerplant--steam, gas turbine, or Diesel engines--in recent years cost over 40 cents per million Btu. This is not a severe handicap, however, for a peaking duty thermal plant since fuel use by such a plant is relatively low. Recent massive oil discoveries in Alaska provide some hope that the cost of oil may be reduced.

Nuclear Plants

About 30 years ago laboratory scientists first realized that energy released by nuclear fission in chain reactions could be used for electric power generation. In the intervening years, the technology of nuclear power generation has moved from the laboratory to commercial plants. Considering the extreme difficulty and complexity of the technology, the pace of progress has indeed been remarkable.

Extensive efforts in physics, chemistry, metallurgy,

radiological and health sciences, and engineering during the past 25 years have provided a foundation for nuclear power generation. Programs in nuclear weapons production and naval ship propulsion have provided major industrial capabilities including facilities for large volume nuclear material enrichment and chemical processing. These activities have been of great value for development of civilian nuclear powerplants.

Present Status

While the first developmental plants have cost more than alternative conventional facilities, nuclear powerplants now being built will be low enough in cost to exert great competitive pressure. They have contributed both to major reductions in the price of coal and coal transport, and served as a powerful stimulus for improvement in alternative power generating sources.

Notwithstanding the excellent progress to date, the future of nuclear energy in the power industry depends on rates of progress along many difficult paths and also the extent to which improvements are achieved in reducing the cost of electricity from conventional plants. Conclusions are therefore subject to wider than usual variation, influenced not only by the optimistic or pessimistic character of the analyst with respect to nuclear technology, but also by his familiarity with the prospects for advancement in competing sources of power supply.

The demonstration that nuclear power is practical and reliable is sufficient to assure its utilization in applications which take advantage of one or both of its two most important unique qualities. These are the ability to produce large quantities of electricity from a very small although not inexpensive inventory of fuel, and to operate without requiring combustion air which avoids releasing large quantities of combustion products to the atmosphere. These attributes alone, however, will not assure extensive use of nuclear energy as a source of electricity for the power industry in the foreseeable future. Nuclear power must offer electricity at a cost lower than other available means, if it is to be widely used. It is toward this end that the major research and development effort is now directed.

Like ordinary fossil fuel-fired plants, nuclear powerplants use heat to produce steam to drive turbine generators. The kilowatts of power capacity and the kilowatt-hours generated from either source are undifferentiated and are transmitted and distributed in the same way. The major difference is that conventional thermal plants use heat produced by combustion of fossil fuel in a furnace, but nuclear plants use heat produced by fission of nuclear fuels in a reactor. Basically a nuclear reactor is substituted for a fossil-fuel boiler.

Nuclear plants require minimum space for fuel storage and discharge no combustion products to the atmosphere (San Onofre plant, Southern California Edison Co.).

Economics of Nuclear Generation

Early stages of civilian nuclear development have been accelerated by government expenditures. These programs have included financial assistance to privately owned projects, research in government laboratories, savings to individual companies from the use of the government's large volume fuel preparation and processing, and waste disposal by the government for national security programs. Other assistance has included "buyback of plutonium" or waiver by the Atomic Energy Commission of rental charges for nuclear materials during early years of nuclear power operation.

Both government and industry recognize that, when specific types of nuclear powerplants approach levels competitive with fossil-fuel plants, further development of these reactor types should proceed without government financial assistance. The industry will be assuming financial independence in other ways. Legislation was enacted in

August 1964, which in effect requires private ownership of new fuels needed for reactor use after December 31, 1970, and calls for terminating all outstanding leases of fuels by June 30, 1973. At the present time all commercial power reactor fuel is being reprocessed by Nuclear Fuel Services in New York. The General Electric Company has a fuel processing plant in Illinois. Other large national companies are also considering construction of additional fuel processing capacity. However, the frontiers of research and development for further new scientific and technical advances in perfecting breeder reactors and other more advanced nuclear reactors will still need government sponsorship and financial aid.

As previously noted, the nuclear powerplant is much like a conventional steam plant except that a nuclear reactor is used instead of a furnace burning fossil fuel. Shielding must be provided to contain hazardous radiation during normal operation, and special containment facilities and other safeguards must be incorporated to prevent the escape of radioactive material in the improbable event of a reactor accident. For these and other reasons, a nuclear plant is likely to have higher construction costs than a conventional plant. However, comparative design studies have indicated that the capital costs per unit of capacity for a nuclear plant should decline even more rapidly with increasing capacity than do conventional plant costs. Accordingly, the capital cost disadvantage of nuclear plants, in comparison with conventional plants will be less significant for larger plants.

More specialized operating staff and higher maintenance costs for some equipment are required for nuclear than for conventional plants. Accordingly, nuclear plants have been relatively more expensive to operate and maintain than conventional plants. However, this difference is expected to decline with increasing nuclear plant capacity and greater operating experience.

It is anticipated that future fuel cycle costs will be lower because of substantial improvement by 1980 of the energy yield in subsequent fuel loads in either the present types of water reactors or in improved reactors. In more recent quotations for new plants, nuclear suppliers have anticipated simplification and improvement in fuel fabrication and other fuel cycle improvements, and quotations have assumed lowered cost achieved by larger volume of sales.

These potential improvements point in the direction of increased output over initial design capacities, decreased unit costs in dollars per kilowatt of capacity, and decreased fixed charges and fuel cycle and other costs per kilowatt-hour.

In view of the sharp effect of increases in unit size in reducing the cost of nuclear power, the maximum sizes in which it

is possible to build nuclear plants are of special interest. Construction of mammoth nuclear-electric power stations with several reactor units at one site may be anticipated. The handicap of rigorous site requirements could be overcome, at least in some degree, by building several reactor units at a single site. Unit costs could also be reduced by sharing of fuel handling and other facilities among the units, and perhaps, in the case of some designs, by the use of common containment.

Fully exploiting the multiunit approach could result in a very large capacity nuclear station, suggesting the possibility of several utility systems joining forces to establish a nuclear generation center. While such a development would conserve nuclear plant sites, the economies of construction and operation would have to be balanced against the extra costs of transmitting the power from a single source throughout extensive market areas and the disadvantage to national defense from concentration of capacity. The establishment of a large capacity transmission grid covering broad areas of the country would tend to minimize the transmission costs and enhance the potential savings in the construction of such a nuclear complex.

Estimates of nuclear plant production often employ the assumption that the long-term maximum average output of nuclear plants will be about 80 percent of maximum capacity. Insofar as availability is concerned, this assumption may even be conservative. Considering the generally low pressures and temperatures in the nuclear steam cycle of contemporary water reactor designs, the nuclear turbogenerators and heat exchangers of these reactors may prove relatively dependable compared to today's high-pressure and temperature conventional plants. Reactor refueling, maintenance, and other factors could account for offsetting sources of outages for nuclear plants in comparison with conventional plants. Attempts are being made to reduce outages for refueling. For example, some reactor designs provide for on-line refueling but it may be that the cost of the equipment to expedite this operation will be greater than the savings.

Availability itself may not control the extent to which a particular nuclear plant will be used. Load conditions, and possibilities for use of other low cost alternatives including improved nuclear plants, will determine the capacity factor of each plant. Considering the fuel cost advantages likely for large reactors, it is expected that large nuclear plants will be favored for the highest level of output in the system complex. At times during the prime years of the plant's life, nuclear units may operate at plant factors between 80 and 90 percent, declining subsequently as lower cost base load plants, probably of improved nuclear type, are added to the system. The pattern should follow that of conventional plants except that nuclear plants will be used

at higher capacity factors, because of their lower operating costs.

Another factor in the extent to which nuclear plants will be used is the displacement of their capability by hydroelectric energy which is otherwise unusable. Substantial regional benefits will be achieved by such fuel displacement through coordinated operation of thermal and hydro generation. The problems in such operation are new and unique to the electric utilities and the suppliers of nuclear systems, particularly the suppliers of nuclear fuels. Studies of such coordination are only beginning.(29)

The prediction of base load operation, as discussed above, is appropriate for the early economically competitive nuclear plants, but it may not be appropriate for all plants when nuclear power becomes a substantial fraction of a system's power supply. Typically, minimum night-time system loads are only about two-thirds of the daytime peaks. When more than this fraction of the peak is supplied by nuclear plants, there must be some reduction in off-peak output to follow the load decline. Further increases in the nuclear capacity will then require that these plants be increasingly prepared to "follow" the system load variation. All experience thus far indicates that nuclear plants have excellent loading flexibility--actually superior to large conventional steam units. However, future nuclear plants designed for high pressure and temperature operation may lose this margin of superiority.

Steam leaving the low pressure exhaust of a nuclear plant turbine is liquefied in the condenser, a process requiring a considerable flow of cooling water through the condenser. Nuclear plants now operating have steam turbines of lower efficiency than those now forming part of modern high-pressure, high-temperature fossil-fuel fired plants. This is reflected in a greater condenser cooling water requirement. For a 1,000-megawatt nuclear plant with a cooling water temperature rise of 20°F., the flow through the condenser would be about 1,620 cubic feet per second. If an evaporative cooling tower were used for this plant, cooling water system consumptive use would be 34.3 cubic feet per second. The consumptive use for steam loop make-up water would be about 0.2 cubic feet per second.

Nuclear Safety

Nuclear fission is accompanied by the emission of direct radiation and by the formation of a variety of radioactive fission fragments that will emit radiation over various time periods during which they decay. Therefore, it is imperative to provide safeguards to avoid contamination of the working areas of the plant and the environment surrounding the plant.

Government and industry have acted in three ways to avoid serious consequences: (1) by safeguards to hold normal routine release to minor levels or to hold accidental release of hazardous radiation and radioactive products within the reactor structure; (2) by containment structures and other safeguards to keep within the plant any accidental release of hazardous radiation which occurs; and (3) by zoning measures to prevent whatever radiation and radioactive products may escape inadvertently, in spite of multiple safeguards, from causing harm to the inhabitants in the vicinity.

It is difficult to determine the kinds and extent of radiation doses which under innumerably different kinds of conditions should be regarded as likely to cause harm. The Atomic Energy Commission, international agencies, and others have evolved standards and criteria based upon exposure data and expert judgment as to what limitations and requirements may be essential to achieve adequate protection. Further experience may lead to tightening or relaxing the criteria which may be applied in the future.

The Atomic Energy Commission has placed much stress on safety in its civilian nuclear program. Research and development in radioactive waste management have been underway for many years, and a companion program in reactor safety was started in 1955. An expanded and accelerated program was initiated in 1961, which includes a wide range of engineering scale tests and evaluation studies relating to reactor safety.

The chance that some accident might occur has led to major efforts to reduce the likelihood of accidents and minimize the consequences, efforts which to date have been highly successful. To assure a high degree of safety, nuclear reactors must be designed and operated with the utmost care to reduce the probability of accidental dissemnination of radioactive products. These safeguarding steps must include great care in plant design, extensive instrumentation and monitoring, requirements for precision and reliability of components, provision of multiple auxiliaries and services to reduce risks of equipment or operating failure, special care in fuel handling and storage, provision of shielding and structural and operating safeguards intended to contain direct radiation and radioactive fission products, appropriate means for controlled release of radiation when desirable, rigorous control to assure proper construction, operating procedures, and maintenance, and frequent inspection and testing of all safety procedures and equipment.

The radiation hazards of a nuclear accident can be further reduced by prescribing restricted or exclusion areas in the plant vicinity. Thus, if substances emanating from a reactor must travel several miles through the air before they can reach substanial

numbers of people, their hazardous character can be reduced not only by natural dispersion and dilution in the atmosphere but also through partial decay of the radioactive and toxic products during the time of movement out of the restricted zone. Therefore, AEC has utilized distance from the reactor to people as one of the several safeguards in nuclear plant site selection criteria.

The possible effect of earthquakes is an additional question often raised in connection with the location and design of nuclear plants in earthquake-prone areas. An AEC report on earthquakes (1) analyzes various ways in which earthquakes might cause mechanical or structural failure and disrupt plant equipment, services, or protective controls and thereby produce effects on reactors which could lead to more severe consequences. The analysis outlines the special considerations and precautions in site selection, design, and engineering to be taken in the planning and construction of the plant to offset the effect of unusual seismic forces. The geological conditions at sites for nuclear plants proposed for an earthquake-prone area must receive especially thorough examination and all parts of the facility must be checked for strength and functional performance to resist the shock loadings that can be imposed by severe earthquakes.

Accidents can happen but, in view of the multiple safeguards and precautions built into a nuclear plant, a combination of events which could produce a nuclear accident involving harmful radiation effects in inhabited areas is extremely improbable. If any reasonably conceivable accident were to occur, such as a break or major leak in a line of the primary cooling system, ultimate release of harmful radiation would not occur except as a result of a series of failures of safety features. A breakdown of all of the numerous independently operative safety controls for stopping the reactor process must have occurred before the nuclear material conceivably could melt down and produce heat and pressure which could cause radiation and radioactive products to escape from the reactor area. Even then, no public harm would result without the further combination of the failure of the containment shell or suppression chambers to retain the radioactive materials. If some of the radioactive material did escape from the plant, it would be subject to the effects of decay and dilution in reaching inhabited areas. The consequences of any nuclear accident are greatly minimized by the criteria, standards and procedures employed by AEC in the licensing, testing, operation, maintenance, and inspection of nuclear projects. The safety record in the operation of utility sponsored nuclear-electric plants to date has been exceptionally good.

Increasing efforts to reduce air pollution may advance the consideration of nuclear powerplants in some areas. These plants do not release hydrocarbons or other chemical substances which could contribute to air pollution problems. Should much more

elaborate and expensive air cleaning equipment than that now in use be demanded of conventional plants, this increased cost would make nuclear powerplants relatively more attractive.

While it is likely that an extended record of good experience will be required before nuclear plants are built in close proximity to densely populated load centers, this does not mean that the beneficial effects of nuclear plants in reducing air pollution are not already of value. There are few locations where major new conventional plants would be located where freedom from atmospheric pollutants would not be a valuable feature.

Liability insurance presents special problems for nuclear powerplants. Experience to date has been limited to a few years and a small number of plants. Accidents have been few in number and damage small, but there is little statistical basis for establishing risks. Meanwhile, conceivable risk and liability have been considered to exceed the financial capability of the private insurance industry. Accordingly, Congress in 1957 authorized the Federal Government to provide liability protection up to $486 million for any single nuclear accident. The reactor operators have paid the government an annual fee of $30 per megawatt of reactor heat capacity for liability coverage. This usually amounts to about $100 per megawatt of electrical capability.

Owners are required to secure the prescribed amount of private liability insurance up to a limit of $74 million, depending upon size of nuclear plant, as a prerequisite to licensed operation and procurement of federally sponsored liability protection. This is in addition to the Federal liability insurance. Insurance company premiums for nuclear plants are at present higher than premiums for conventional operations.

Other Economic Factors

Any considerable nuclear power industry must stand on its own financial feet. Estimates of nuclear power costs are generally predicated on a large-scale nuclear power industry and escalation of unit sizes well above those that have been built to date. The scale of projected nuclear capacity additions is based on assumptions of cost believed to be consistent with private ownership of plant and fuel, fuel manufacturing, and reprocessing facilities, and normal profits for equipment manufacturers. It is assumed, however, that the Federal Government will continue to participate to some extent in hazard insurance against nuclear loss beyond private coverage.

The Columbia-North Pacific Region already has one nuclear plant, the Hanford plant of Washington Public Power Supply System.

It is of the pressurized water type and operates at low temperature and pressure. Its steam supply is from a federally owned nuclear reactor.

Other nuclear powerplants in service in other parts of the country in 1969 are of various types including pressurized water, boiling water, high-temperature gas cooled and sodium cooled. These plants have a total capacity of 2,037 megawatts. Other nuclear plants with a total capacity in excess of 38,000 megawatts were under construction by 1970.

Nuclear fuel reserves will be increasingly important as more and more plants are built. Estimates of the size of nuclear fuel reserves of the United States are approximate and based on a range of production costs. According to the best information published to date, nuclear fuel consumption by plants existing or to be constructed by 1980 will not amount to more than 15 percent of the reserves estimated to cost less than $10 per pound of uranium oxide. If the allowable cost of uranium oxide is increased to $15 per pound, the economic reserves available are nearly doubled.

Power Exchanges and Imports

A complete load-resource analysis for an area must consider the flow of power into and out of the area. This has an effect on the transmission system required for the area, but its most important effect is on the power resources required to meet the electric load of the area. Sometimes these power flows have a greater effect on the character of the area's internal power supply than might be suggested by their relative magnitude.

Power interchanges between areas are made for a variety of reasons. The most straightforward reason is a surplus of electric energy in one region and a deficiency in the other. Where this surplus is of a firm nature, it provides a firm resource to the importing region. In most instances, however, the resource exists as a surplus only over a limited period of years and therefore provides no firm resource to the importing area on a long-term basis. Under a given load level, power surpluses in an area are not usually available under all circumstances of load and streamflow. In these instances, they usually do not supply firm energy to the importing area and are restricted to such uses as fuel displacement and interruptible industrial loads.

Other reasons for interchange apply to peaking capability. If a region's loads and resources are in balance with respect to energy but a surplus of capacity exists, then that peaking capability can be available for export. Two questions arise with this export. First, will the exporting area agree to continue

installing generators to maintain this surplus? Second, will the exporting system supply the energy which accompanies this peaking, or will it require that the energy be returned during light load periods of the importing system?

Where there is load diversity between the two areas, firm resources may result from an interchange even though both areas have loads and resources in balance. This may be a diversity in hourly loads, but more productively might be a diversity in seasonal loads. To measure the productive diversity consideration of historical or forecasted loads may not be sufficient. There must be a high assurance of diversity for firm benefits to result. If, for example, there is a diversity of one hour in peak loads of the two areas, then an abnormality of only one hour in the peak load of either area might entirely negate the diversity measured for some past period.

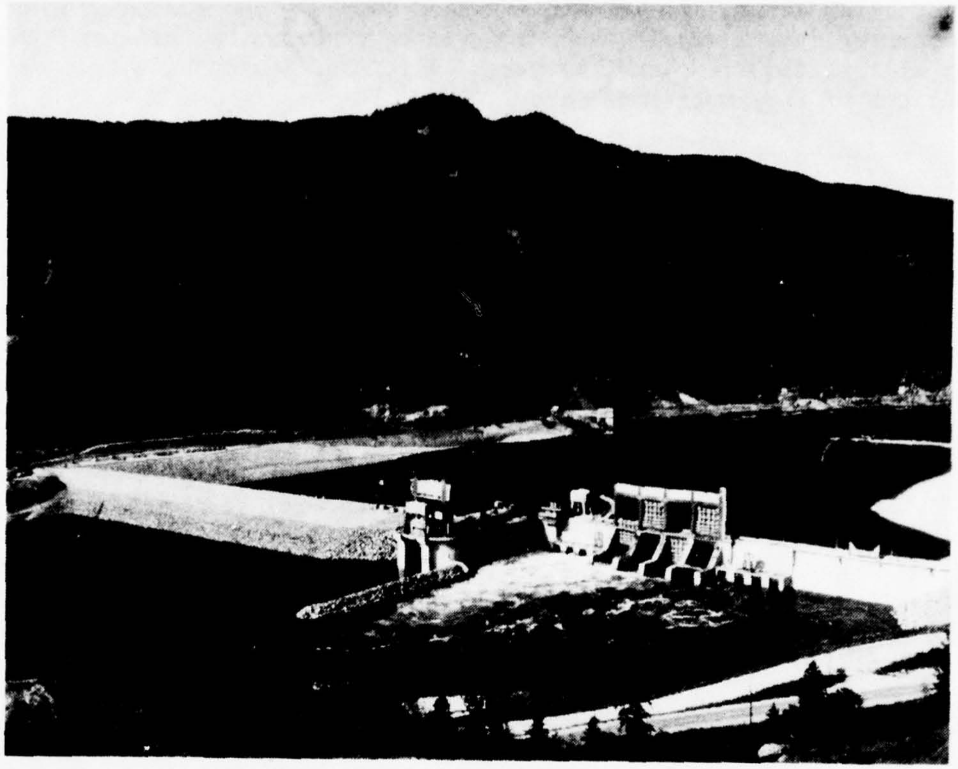
The foregoing discussion by no means exhausts the potential benefits of power exchanges. Exchanges of energy between thermal systems may decrease the total collective cost of energy generation. Ability to exchange peaking power may reduce the overall cost of generating reserves. Other situations have similarly been identified where power exchanges hold promise.

A fundamental necessity for power interchanges with adjacent areas is adequate interconnecting transmission capacity. Sufficient transmission capacity for the Columbia-North Pacific Region to operate as one power system has existed for a considerable time. Capacity for significant interchanges with other areas is developed, such as the three extra-high voltage lines being constructed to the Pacific Southwest. Additional interchange capacity with the Missouri Basin systems and British Columbia will undoubtedly be provided in the future.

Some of the more important interregional interchanges are discussed under the following headings:

Canadian Treaty Power

Under terms of the Columbia River Treaty, Canada was to receive power as reimbursement for regulation of flow by Mica, Arrow, and Duncan reservoirs. Sale of this entitlement by Canada through the Columbia Storage Power Exchange retained the power in the United States but for an interim period. For the early part of this period, most of the entitlement will be exported to Pacific Southwest utilities. By 1983-84, however, all the assignments to California will be withdrawn and the Canadian Entitlement will be used entirely in the Pacific Northwest.



Arrow Dam, one of three Canadian storage projects constructed under terms of the Columbia River Treaty (B. C. Hydro and Power Authority).

Sale of the Canadian entitlement is for identified diminishing amounts of capacity and energy through the year 2003. After that date, the entitlement may therefore result in an export of power from the region with the amount determined each year under terms of the treaty. The magnitude of the entitlement at such a distant date is uncertain; however, sale of the entitlement provides for terminal amounts of approximately 200 megawatts of capacity and 100 average megawatts of energy.

Exchange of Power with the Pacific Southwest

Availability of the three high voltage lines interconnecting with the Pacific Southwest provides opportunities for export of various classes of power. In the early years, in addition to Canadian treaty power, considerable secondary hydro energy will be available for export. Not all the available energy will be exported as the Regional Preference Act, Public Law 88-552, restricts the export to protect energy supplies for Pacific Northwest users. With increased thermal electric installation in the Pacific

Northwest, secondary hydro energy will be increasingly usable for fuel displacement and exports of energy will diminish.

Opportunities for increased hydroelectric peaking installation in the Northwest exist at many of the larger hydro plants. As the incremental cost of such peaking capacity is low, these plants provide an attractive source of peaking for exports over the period until the capacity is required in the Northwest. A portion of this capacity will be sold directly with the remaining portion exchanged for energy, thus incrementing the firm energy supply of the Northwest. By 1985, when the CSPE sales to California have terminated, it is anticipated that 1,342 megawatts of capacity will be supplied the Southwest in return for which 339 megawatts of firm average energy will be received. Other exchanges will raise this average energy to 360 megawatts. Diversity exchanges with Arizona utilities will also provide 922 megawatts of capacity.

Power capability of the Bureau of Reclamation's Central Valley Project in California is the source of power supply to certain public power distribution agencies. To extend the period over which the requirements of these agencies can be met, the Bureau has contracted for a power supply from Pacific Gas & Electric Company, the principal power utility of central and northern California. In return for such a power supply in the more distant future, power in the early future is to be provided the company by the Bureau's purchase of a share of the Centralia thermal-electric plant in the Northwest with the power coordinated and transmitted by Bonneville Power Administration. The purchase is for an amount, which, adjusted for transmission losses, provides 400 megawatts of capacity at the Oregon-California border for a 10-year period beginning January 1, 1972. Energy accompanying this power is scheduled by hours. To the extent this energy exceeds that generated by the 400-megawatt share of the plant, the deficit must be returned before the end of the storage release period. If there is a surplus rather than a deficit, it is stored in Northwest Federal reservoirs and scheduled for subsequent delivery or alternatively spilled, or purchased if usable. Specific charges are provided for transmission, storage, or purchase of surplus.

Exchange of Power with British Columbia

Transmission interconnections with British Columbia have been in operation for many years. In 1966-67, there was a firm import which exceeded the transmission capacity in the United States under certain emergency conditions. Purchase of the Canadian Storage Entitlement in the United States, of course, contractually constitutes an import. Studies were recently initiated by non-Federal utilities of the Pacific Northwest leading to a firm agreement for coordinating the power operation of B.C. Hydro with

the systems party to the Pacific Northwest Coordination Agreement. The long hold-over cycle possible with the large reservoir back of Portage Mountain Dam on the Peace River raises interesting possibilities from such coordination.

At various times it has been suggested that the large hydropower potential in British Columbia provides a possible source of power for the Pacific Northwest. This is a possibility which should not be ruled out, but various factors make it conjectural at this time. One is the accelerating load growth of B.C. Hydro which approaches the ability of the Province to provide new power resources. Another is the complications of the necessary treaty negotiations to make such benefits firm.

Exchange of Power with the Missouri River Basin

It has been suggested that high voltage interconnection of the two Federal power generation and marketing systems in the Columbia and Missouri River Basins would provide valuable power benefits. The last investigation, the final stages of which were not completed, concluded that an interconnection would provide appreciable benefits through resource diversity, hourly load diversity, and thermal energy transfer. Recommendation of the interconnection has been withheld pending further study.

Montana Power Company serves loads and has capability in both the Columbia and Missouri River Basins. Shifts of power supply within the Montana system therefore constitute exports in the technical sense. Power studies, including those under the Pacific Northwest Coordination Agreement, solve this problem through the device of considering Columbia River Basin generation only, with a corresponding load allocation.

Exchange of Power with Utah Power & Light Company

In the past there have been exchange and purchase agreements between Idaho Power Company and Utah Power & Light Company. These have been for definite limited periods, and there is no information that such exchanges should be contemplated on a long-term firm basis.

Exotic Generation Sources

The word "exotic" when used to describe means of generating electric power generally refers to such methods as nuclear fusion, magnetohydrodynamics (MHD), fuel cells, thermionics, photovoltaics, or thermoelectrics. Of these, the greatest hope for a device of high capacity, suitable for electric power system central station

generation, seems to be in either the nuclear fusion, or the MHD type of generator.

"Nuclear fusion" is intended to identify a method of producing very large amounts of heat by uniting or fusing light nuclei such as those of deuterium or tritium as contrasted to production of heat by splitting or fissioning heavy nuclei, Uranium 235 for example, the basic process of existing nuclear powerplants. Although considerable research effort has been and is being exerted in an attempt to produce power by nuclear fusion, it has not yet been accomplished. The indications are that invention of a power generator using a controlled nuclear fusion process is many years, perhaps decades, away.

In an MHD generator, electric energy is produced by forcing a conducting fluid across a magnetic field with the current generated taken off through two electrodes which are connected to the external load. The machine can be designed to generate direct current or alternating current although the reactive power requirements have made the alternating current unattractive. Design of practicable, economically competitive, generators of the MHD type apparently will also require much more research.

Fuel cells of relatively small kilowatt capacity have been built and used as, for example, in the space program (Gemini and Apollo). Their high cost, space requirements, and low output at the present stage of development indicate that they are not likely to be a factor in central station power production for some time, if ever.

Photovoltaic power sources (solar cells) have proved their value and dependability under the severe conditions of outer space, but cost, volumetric requirements, and dependence on sunlight appear to militate against use of these devices in utility system power generation.

Thermoelectric generators depend on the difference in temperature of two separated junctions (hot and cold) of two dissimilar metals for the generation of current. They are exemplified by the thermocouples commonly used in temperature indicators of some types of power equipment and as safety devices in many household, natural-gas fired, space and water heaters. While they are eminently practical for this type of service, they are not satisfactory for large-scale power production because of cost and size limitations.

In thermionic energy converters, heat is supplied at high temperature to a metallic electrode called the emitter and electrons are evaporated from its surface. These electrons are transported through a gap and accumulated on a cooler electrode called the collector. The latter must be cooled to keep it at a lower

temperature than the emitter. An external circuit provides a path for the completion of the flow and a place for useful employment of the electric energy produced. Much research has gone into the development of this method of converting heat directly into electricity. Certain advantages, such as high heat rejection temperature and high output per unit weight, may make thermionic converters preferable to other sources in space modules where these two characteristics are particularly desirable. Their use in the more mundane world of commercial power seems less certain, principally because of their cost which cannot be predicted even approximately at the present state of development.

Another power source less appropriately classifed as "exotic" is geothermal power. Geothermal power may be generated by the release of steam from naturally hot areas underground. The thermal area may be tapped through drill holes and the natural steam conducted to a thermal generating unit.

Hot wells are used for space heating in Boise, Idaho, and Klamath Falls, Oregon. The only significant electric generation from natural steam in or near the region is at Geysers, California. Four wells began producing at that area in 1958, and the steam was supplied by contract to Pacific Gas & Electric Company. Power production began in 1960 with installation of 12,500 kilowatts of generating capacity. In 1970, plant capacity at The Geysers is 82,000 kilowatts, and scheduled to exceed 600,000 kilowatts by 1975.

At the current point in the research and development of the "exotic" generation sources discussed in the foregoing paragraphs, none seems to be far enough along to be considered a likely central station power source. It is, of course, impossible to foretell when some major discovery may be made that will project one or more of these sources into the very forefront of large-scale power production.

STAGING OF ELECTRIC POWER DEVELOPMENT

Up to the present time, the power needs of the region have been met almost exclusively with hydroelectric generation. However, it has been apparent for some time that the region's hydro resources are inadequate to meet future loads. Although there are quite a few undeveloped hydro sites remaining, the load is increasing at such a rate that, even if all of the feasible sites were developed, they would still fall far short of meeting the load by the year 2000. Thermal generation will be required to meet much of the increased demand, and it is anticipated that the thermal capacity of the region will gradually be increased until ultimately it will carry virtually all of the base load. Hydro's role will concurrently change from the current situation, where it meets both the base

and peaking loads, to its ultimate status, where it will be called on primarily to meet peaking loads. This transition from an all hydro to a thermal-base system will take place in stages, as discussed earlier under Reservoir Storage. The years 1980, 2000, and 2020 all represent different stages in this transition.

Since one of the primary objectives of the Columbia-North Pacific Framework Study is to determine the future water requirements of the region, it is necessary to determine the amount of thermal generation required so that its cooling water requirements can be estimated. By making system power regulation studies, it is possible to determine the amount of hydro generation available and hence the amount of thermal generation required at each of these stages.

Resources to Meet Load in 1980, 2000, and 2020

Both hydro and thermal resources will be required to meet loads at each of the three stages. The physical characteristics of each of these resources were discussed earlier in this section under Electric Power Resources. However, certain assumptions have to be made as to how each will fit into the load pattern at each stage. Further assumptions have to be made regarding the degree of coordination to be attained in the operation of the region's power resources, and the amount of reserves to be provided.

Projects for Base Load

There are two major sources of base load hydro generation. The first includes run-of-river plants capable of substantially continuous operation at full hydraulic capacity throughout the year. Examples are the present Bonneville and Rock Island plants and numerous small, older plants included in the independent Resources category on tables 37 and 38. The amount of base load capacity from this source will probably decrease as some of these plants are expanded to become peaking plants and others are abandoned or redeveloped as peaking plants.

The second source consists of a portion of the output of the plants designed for peaking operations. Because of the necessity for maintaining at least a minimum continuous water release for other water uses downstream, some portion of the plant capacity of each hydro plant will automatically be assigned to base load service. The amount of base load capacity from this source will probably be fairly continuous through most of the period of study.

It is anticipated that thermal generation will gradually assume the bulk of the base load. The number and type of plants required and the siting of these plants are discussed later under Site Selection of Thermal-Electric Plants.

Peaking Units

There are a number of alternative sources of peaking capacity in the region: additional units at existing hydroelectric plants; new, low plant factor conventional hydroelectric plants; gas turbines and Diesel peaking units; and oil-fired steam-electric peaking plants.

The ability to start quickly and change power output rapidly makes hydroelectric plants especially suitable for carrying peak loads and supplying spinning reserve. In addition, the annual cost of providing additional peaking capacity at hydroelectric plants is usually less than the cost of additional capacity from alternative sources. This is because the cost of dams and reservoirs for storage has already been incurred and the additional cost reflects only the intake, conduit, powerhouse, and equipment. A prime example is the third powerhouse at Grand Coulee. Listed on table 33 are some of the other projects where provision has been made for installing additional capacity. In addition, the potential exists for installing additional units beyond those listed in table 33 at Grand Coulee, Chief Joseph, and possibly other projects.

As these additional units are added and thermal capacity is installed to carry the base load, the operation of most hydro plants will become mainly a peaking operation. A portion of this generation, such as future additions to the third powerhouse at Grand Coulee, will operate at the very peak of the load, while other hydro plants will carry lower portions of the peak load.

There are still a number of sites available in the region where low plant factor conventional hydro plants can be constructed economically. Most of the plants listed in the inventory of potential hydroelectric projects fall into this category. These resources are included in the load-resource analysis for Plan A. However, it must be recognized that, due to competing uses for the river reaches where these plants would be constructed, they cannot be counted on as firm resources. For this reason, a second analysis was made, assuming that peaking resources other than hydro would be required to meet the new loads developing after the 1990's.

Thermal-electric peaking plants fall into two categories: the very low capacity factor plants such as gas turbines and Diesel-electric, and the 10 to 30 percent capacity factor range steam-electric peaking plants.

After the installation of the last units at hydro plants is completed in the 1990's, additional very low capacity factor generation will be required, which could be met by gas turbines or Diesels. However, pumped-storage may prove to be a more economical means of meeting this portion of the load.

Oil-fired steam-electric peaking plants are currently recognized as the alternative to hydro in the 10 to 30 percent capacity factor range. However, with thermal generation assuming most of the base load, more and more hydro will be available for peaking, and it is anticipated that conventional hydro, along with pumped-storage, will be able to carry this portion of the peak load through 2020. Hence, at the present time, it does not appear that steam electric peaking generation will be required.

Pumped-Storage

As discussed earlier, the peaking requirements of the Pacific Northwest will probably be met through 1990 by adding conventional units at existing hydroelectric projects. These additional units can be installed, in most cases, more economically than developing pumped-storage projects. By the year 2000, however, studies indicate a regional deficit of 2,000 to 5,000 megawatts of peaking capacity. By the year 2020, this requirement will increase to about 50,000 megawatts. This portion of the load could readily be carried by pumped-storage, and the pumped-storage site inventory discussed earlier shows that there is an abundance of good sites in the region. Numerous sites exist near the Seattle and Portland load centers. With development of less than 10 percent of these sites, the region's peaking capacity can be satisfied beyond the year 2020.

Early pumped-storage developments will favor sites which are capable of a relatively long generating period of 12 to 14 hours daily at near full plant capability. By the end of 2020, when thermal generation carries a greater share of the base load, some pumped storage may operate for periods of only 6 to 8 hours daily. Because of the longer daily operating requirements, the first pumped-storage plants will require large storage capacity.

Table 37. Staging of Hydro Resources Plan A, Maximum Hydro System, Columbia-North Pacific Region

		1980 Conditions				2000 and 2020 Conditions			
Project	Subregion	Usable Storage (1,000 ac-ft)	Units	Prime Energy (Average MW)	Dependable Capacity (MW)	Usable Storage (1,000 ac-ft)	Units	Prime Energy (Average MW)	Dependable Capacity (MW)
Coordinated Columbia River System									
Storage									
Mica	Canada	7,000	-	-	-	7,000	-	-	-
Arrow	Canada	7,100	-	-	-	7,100	-	-	-
Libby	1	4,965	4	189	179	4,965	8	144	966
Duncan	Canada	1,402	-	-	-	1,402	-	-	-
Kootenay Lake	Canada	817	-	-	-	817	-	-	-
Smoky Range	1	-	-	-	-	1,510	5	56	330
Spruce Park	1	-	-	-	-	600	2	39	380
Hungry Horse	1	3,161	4	105	183	3,161	4	98	328
Kerr (Flathead Lake)	1	1,219	3	119	177	1,219	4	113	247
High Buffalo Rapids	1	-	-	-	-	668	8	110	516
Ninemile Prairie	1	-	-	-	-	885	4	18	92
Noxon Rapids	1	231	4	168	359	231	5	148	538
Albeni Falls (L. Pend Oreille)	1	1,155	3	22	18	1,155	3	15	39
Enaville	1	-	-	-	-	700	2	20	80
Post Falls (L. Coeur d'Alene)	1	223	5	8	14	223	New	8	25
Long Lake	1	105	4	42	73	105	New	58	150
Grand Coulee	2	5,232	22	2,041	4,316	5,232	30	1,901	9,229
Chelan	2	676	2	39	53	676	2	38	53
Brownlee	5	980	4	233	424	980	6	197	675
High Mountain Sheep	6	2,250	3	555	1,373	2,250	7	482	3,430
Challis	6	-	-	-	-	350	NA	18	125
Pahsimeroi	6	-	-	-	-	1,042	NA	21	125
Tailholt	6	-	-	-	-	470	NA	39	250
Crevice	6	-	-	-	-	2,300	NA	313	2,200
Lower Canyon	6	-	-	-	-	2,500	NA	358	2,500
Dworshak	6	2,000	3	168	405	2,000	6	157	1,219
Round Butte	7	274	3	95	248	274	3	89	330
Run-of-River									
Libby Reregulator	1	-	-	-	-	Pondage	4	25	50
Kootenai Falls	1	Pondage	3	115	207	"	5	114	345
Quartz Creek	1	"	3	38	90	"	4	39	120
Thompson Falls	1	"	6	36	40	"	8	37	75
Cabinet Gorge	1	"	4	113	230	"	4	102	230
Box Canyon	1	"	4	50	77	"	4	48	77
Boundary	1	"	6	352	932	"	6	331	932
Upper Falls	1	"	1	8	10	"	New	8	30
Monroe Street	1	"	5	6	7	"	New	6	36
Nine Mile	1	"	4	11	18	"	New	11	44
Little Falls	1	"	4	19	36	"	New	19	66
Chief Joseph	2	"	27	1,049	2,443	"	27	1,024	2,443
Wells	2	"	10	419	784	"	10	409	784
Rocky Reach	2	"	11	615	1,253	"	11	577	1,253
Rock Island	2	"	10	164	167	"	10	156	151
Wanapum	2	"	10	553	981	"	16	506	1,449
Priest Rapids	2	"	10	530	912	"	16	495	1,362
Ben Franklin	2	"	16	350	938	"	16	328	938
Oxbow	5	"	4	105	220	"	5	86	275
Hells Canyon	6	"	3	170	450	"	4	167	589
Freedom	6	-	-	-	-	"	NA	109	800
China Gardens	6	-	-	-	-	"	5	140	625
Lenore	6	-	-	-	-	"	NA	54	375
Myrtle	6	-	-	-	-	"	NA	51	350
Lapwai	6	-	-	-	-	"	NA	27	175
Asotin	6	Pondage	3	165	466	"	5	151	776
Lower Granite	6	"	3	229	466	"	6	208	932
Little Goose	6	"	3	224	466	"	6	205	932
Lower Monumental	6	"	6	235	932	"	6	208	932
Ice Harbor	6	"	6	220	693	"	6	199	693
McNary	7	"	14	633	1,127	"	20	617	1,610
John Day	7	"	16	972	2,484	"	20	912	3,105
Pelton	7	"	3	39	124	"	3	41	124
The Dalles	7	"	22	747	1,894	"	22	692	1,894
Bonneville	7	"	16	623	1,049	"	16	582	1,049
Subtotal		38,790		12,612	27,318	49,815		13,104	49,448
Independent Resources		11,438		2,111	5,059	15,372		2,442	6,536
TOTAL		50,228		14,723	33,377	65,187		15,546	55,984

Sources: 36 (System Power Study CT-1-1980), 43 (System Power Study NP-5-2010).

Table 38 - Staging of Hydro Resources Plan B, Minimum Hydro System, Columbia-North Pacific Region

Project	Subregion	1980 Conditions: Usable Storage (1,000 ac-ft)	Units	Prime Energy (Avg. MW)	Dependable Capacity (MW)	2000 and 2020 Conditions: Usable Storage (1,000 ac-ft)	Units	Prime Energy (Avg. MW)	Dependable Capacity (MW)
Coordinated Columbia River System									
Storage									
Mica	Canada	7,000	-	-	-	7,000	-	-	-
Arrow Lakes	Canada	7,100	-	-	-	7,100	-	-	-
Libby	1	4,965	4	194	209	4,965	8	144	953
Duncan	Canada	1,402	-	-	-	1,402	-	-	-
Kootenay Lake	Canada	817	-	-	-	817	-	-	-
Hungry Horse	1	3,161	4	99	167	3,161	4	98	328
Kerr (Flathead Lake)	1	1,219	3	113	166	1,219	3	113	185
Noxon Rapids	1	231	4	151	404	231	5	148	538
Albeni Falls (L. Pend Oreille)	1	1,155	3	20	19	1,155	3	15	41
Post Falls (L. Coeur d'Alene)	1	223	5	8	14	223	5	8	15
Long Lake	1	105	4	42	73	105	4	38	73
Grand Coulee	2	5,232	22	1,940	4,494	5,232	30	1,901	9,229
Chelan	2	676	2	38	50	676	2	38	53
Brownlee	5	980	4	220	368	980	6	197	675
Dworshak	6	2,000	3	158	359	2,000	3	157	460
Round Butte	7	274	3	88	237	274	3	89	291
Run-of-River									
Libby Reregulator	1	Pondage	0	-	-	Pondage	0	-	-
Thompson Falls	1	"	6	37	40	"	6	37	40
Cabinet Gorge	1	"	4	104	230	"	4	102	230
Box Canyon	1	"	4	48	76	"	4	48	76
Boundary	1	"	4	335	632	"	6	331	932
Upper Falls	1	"	1	8	10	"	1	8	10
Monroe Street	1	"	5	6	7	"	5	6	7
Nine Mile	1	"	4	11	18	"	4	11	18
Little Falls	1	"	4	19	36	"	4	19	36
Chief Joseph	2	"	27	1,048	2,443	"	27	1,024	2,443
Wells	2	"	10	417	784	"	10	409	784
Rocky Reach	2	"	11	589	1,253	"	11	577	1,253
Rock Island	2	"	10	155	154	"	10	156	154
Wanapum	2	"	10	515	981	"	16	506	1,449
Priest Rapids	2	"	10	505	912	"	10	496	912
Oxbow	5	"	4	94	186	"	5	86	253
Hells Canyon	6	"	3	184	450	"	3	167	450
Lower Granite	6	"	3	215	466	"	6	208	932
Little Goose	6	"	3	212	466	"	6	205	932
Lower Monumental	6	"	6	217	932	"	6	208	932
Ice Harbor	6	"	6	212	693	"	6	199	693
McNary	7	"	14	635	1,127	"	14	617	1,127
John Day	7	"	16	935	2,484	"	20	912	3,105
Pelton	7	"	3	41	124	"	3	41	124
The Dalles	7	"	22	714	1,894	"	22	692	1,894
Bonneville	7	"	16	597	1,049	"	16	582	1,049
Subtotal		36,540		10,924	24,007	36,540		10,593	32,676
Independent Resources		7,671		1,705	3,655	7,671		1,655	3,675
TOTAL		44,211		12,629	27,662	44,211		12,248	36,351

Sources: 45 (System Power Studs NP-6-2010), 46 (System Power Studs NP-7-1980).

Although the regional analysis does not show any immediate requirement for pumped-storage, individual utilities may find that pumped-storage can be economically added to their systems before all of the region's conventional units have been added. In addition, there may be some opportunities to obtain low-cost peaking by installing reversible units instead of conventional units at existing plants. An example of this would be the units now being installed at the Grand Coulee Pumping Plant. Other pumped-storage projects currently being studied are discussed in the pumped-storage portion of Hydroelectric Resources.

Generating Reserves

In order to provide the high quality electric service that customers expect, the electric power systems must maintain or have access to more generating capacity than their estimated peak load. This reserve generating capacity must be provided to meet three requirements: (1) unscheduled or forced outages, (2) scheduled outages for general maintenance and repair, and (3) contingencies for unanticipated load growth. The amount of generating reserve necessary to satisfy these requirements varies widely from system to system depending on system size; the types, sizes, and age of generating units in the system; maintenance requirements; number and capacity of interconnections with other systems; etc. The load-resource analyses shown on tables 39 and 40 include allowances of about 15 percent of the thermal capacity requirements as an energy reserve. An allowance of 12 percent was added to the forecasted peak load to provide the other reserve requirements cited above.

System Coordination

The system power regulation studies which have been made to determine the load-carrying capability of the Pacific Northwest System assumed that the operation of all projects, including thermal, will be fully coordinated and will take full advantage of diversities in streamflows and loads to produce maximum benefits consistent with other water uses such as irrigation, navigation, flood control, recreation, water quality, fish and wildlife, etc. It is assumed that the capacity of the transmission system will be adequate to convey electric energy from the various plants to the load centers. Further, it has been assumed that there will be interconnections between the numerous electric utilities to permit flexible power exchanges among the utilities and thereby avoid spilling of usable water because of the inability of a particular utility to store excess water for later use.

Several organizations have been formed by the utilities and power producers to promote regional and interregional coordination. Most important are the Northwest Power Pool, the Pacific Northwest Coordination Agreement, and the Western Systems Coordinating Council, discussed earlier under Present Situation.

System Performance

The way in which the power generating system will perform under different load conditions can be ascertained from the seasonal and weekly streamflow regulation studies. As system performance has a major effect on the staging of electric power resources, some of the major system characteristics are discussed below.

Hydropower forms the backbone of the region's power generating system, and will, because of its flexibility, continue to play an important role in the future when the majority of the load will be carried by thermal. In making a load-resource analysis, the first step is to determine the load-carrying capability of the hydro system. Once this is done, the magnitude of the requirements for the other types of power resources can readily be determined. The difference between the projected energy load and the load-carrying capability of the hydro system is the energy "deficit" of the system, that part of the load which must be carried by base load thermal plants. In the early years, this combination of conventional hydro and base load thermal will be capable of carrying the entire peak load as well. But, by about the year 2000, when all of the feasible hydro will have been constructed, a deficit will develop, which will be met by pumped storage, gas turbines, or other peaking plants. The amount of additional *peaking capability required is the difference* between the projected peak load and the sum of the hydro peaking capability and the base load thermal capacity.

Hydroelectric Resource Analysis

The basis of the hydro resource analysis is the seasonal system regulation study, which simulates the operation of the system of projects on a monthly basis through a 30-year historical sequence of streamflows (July 1928 through June 1958). By regulating system storage through 30 years of streamflows, it is possible to obtain a good picture of how the system will perform under the wide variation in streamflow patterns which could be encountered in actual operation. From the regulation study several important parameters are obtained: average annual energy, prime energy, and dependable capacity, both for the system and for individual projects. The average annual energy is the average energy generated during the 360-month study period while values which actually define the hydro system's dependable output, prime energy, and dependable capacity are related to the critical period and are defined later.

In making the hydro system regulation, hydro resources are divided into two categories: (1) the coordinated Columbia River hydro system and (2) the independent resources. The former is the

system of storage and run-of-river plants located on the Columbia River and major tributaries, whose operation is closely coordinated, both hydraulically and electrically, on a seasonal basis. This system forms the bulk of the region's hydroelectric capability. The independent resources are the remaining hydroplants in the region, mostly smaller, which are located such that their operation has little effect on the regulation of the Coordinated Columbia River System. Most of them are located in three general areas: (1) the Upper Snake, (2) tributaries of the Columbia below Bonneville, and (3) Puget Sound area and coastal streams. Although not connected hydraulically, the operation of these projects is closely coordinated electrically with the Columbia River system.

Independent Hydroelectric Resources

The capabilities of the independent resources have been determined for different levels through a special regulation study undertaken by the Power Planning Committee of the Pacific Northwest River Basins Commission.(23) This regulation study was conducted using the same 30 years of historical streamflow data and using the same general assumptions as are discussed below for the coordinated Columbia River system. The study lists the performance of proposed independent hydro projects as well as the existing ones. In making the hydro resource analysis for the Columbia-North Pacific study, systems of independent projects were assumed for the different levels of development, and the energy and capacity values summarized for each month. These values were then subtracted from the regional load estimates (table 23), leaving the residual load which must be carried by the coordinated Columbia River system and the thermal resources.

The Critical Period

The key to the determination of the load-carrying capability of the hydro system is the critical period. The critical period is the most adverse sequence of streamflows that occurred during the 1928-1958 period and as such defines the system's prime energy and dependable capacity, the maximum energy and capacity that the hydro system can be depended upon to carry under these extreme conditions.

In a long-term sequence of flows such as the 30-year period being studied, there are usually several different adverse flow sequences. The sequence of flows that is the most adverse depends on the amount of storage available to augment the low natural flows (thereby increasing system energy carrying capability). With the amount of storage presently in the Columbia River hydro system, the critical period is based on the 8-1/2 month sequence of flows that occurred during the fall and winter of 1936-37. Depending on the

scheduling of the filling of the Libby, Mica, and Dworshak storage reservoirs now under construction, the 20-1/2-month critical period 1943-45 may define system capability for 1 or 2 years. However, once these three reservoirs are all in operation, system capability will be defined by the multiyear critical streamflow period of 43 months extending from August 1928 through February 1932. While it is possible that more adverse conditions could occur, a cursory study of historical streamflow data back to 1878 has shown that the 43-month critical period occurring in this 30-year period is the worst in recorded history; and, therefore, it is felt that the 1928-58 period of analysis is adequate for determining system capability.

More specifically, the critical period is the sequence of months wherein all reservoir storage is released to maximize hydro system energy-carrying capability. Thus, by definition, the critical period starts at a point in time when, due to adequate runoff in preceding months, all reservoirs in the system are full. During the following months of adverse streamflow, the system is regulated in such a manner that the load can be met using a minimum amount of thermal generation. The end of the critical period is defined as the point in time at which all reservoirs in the system are empty (succeeding historical flows being sufficient to eventually refill the reservoirs).

The average hydro generation during the critical period is identified as the system prime energy. The minimum peaking capability of the system measured against the month of maximum peaking demand defines the system's dependable capacity. This month usually occurs at or near the end of the critical period.

Monthly Operation During the Critical Period

For 1980 level of development and on through the early part of the 1990's, the load-carrying capability (prime energy and dependable capacity) of the Columbia River hydro system will be determined on the basis of the 43-month critical streamflow period. In establishing the basic reservoir rule (operating) curves, power regulation studies were made of the critical streamflow period, in which all available power storage was drafted in a manner to produce the maximum possible hydro system prime power while at the same time serving all higher priority nonpower water requirements and operating consistent with system constraints. Under the 1980 conditions where maximization of hydroenergy is the main consideration, these critical period power regulation studies determine the firm energy load-carrying capability of the Pacific Northwest Coordinated System and of each interconnected system. By necessity, supplemental studies must be performed annually to reflect increased unanticipated loads, revised maintenance schedules, delays, or

accelerations in new or additional resources scheduled, retirements, increased irrigation depletions, and other consumptive losses, etc.

Under 1980 conditions, where maximization of hydroenergy is the prime objective, the drafting of large amounts of storage reduces the head at the storage projects, resulting in decreased peaking capability. It is expected that in the early 1990's, all of the generators planned for the major hydroelectric projects will have been installed to meet peak load requirements. Therefore, in order to obtain additional peaking capability at the least cost under year 2000 and 2020 conditions, reservoirs will be regulated to maximize peaking capability rather than hydroenergy. This operation is justified because sufficient thermal capacity will be available by then to carry the majority of the base load energy requirements. Streamflow regulation studies will establish the extent that storage can be withdrawn at each reservoir, recognizing all higher priority requirements and constraints and still maintaining maximum capability to serve the system peak load in January.

Under 2000 and 2020 conditions, with hydroplants being primarily regulated for peaking instead of firm energy production, operation of the reservoirs will be undertaken on an annual basis and the critical period will no longer have significance.

Monthly Operation with Long-Term Streamflows

As discussed above, the mode of hydroelectric system operation will change as the peak load requirements exceed the availability for installing additional hydrocapacity. Under 1980 conditions, where maximization of hydroenergy is the main consideration, it will be necessary to develop two sets of rule curves for each reservoir as a part of the coordinated system. The first set will be designed to protect the firm energy load-carrying capability, that is, to insure that reservoir withdrawals will be apportioned in such a manner that should critical streamflows occur, the firm energy load-carrying capability will be maintained throughout the period. A second set, developed on the basis of long-term streamflows will be designed to protect the storage refill ability of the reservoirs. Under conditions representative of years 2000 and beyond, where the maximization of peak load-carrying capability is the main consideration, rule curves will be designed so that maximum turbine output would be available for the critical midwinter peaking period. Rule curves from mid-January through the flood season would be based on variable refill curves forecasting probable inflows and simulated daily flood regulation studies.

Thermal Base-Load Plant Operation

In making this study it was assumed that the thermal plants used in meeting base-load demands would be plants designed to operate most efficiently on a continuous basis. For purposes of determining capability in meeting system energy requirements, it is generally assumed that these plants will operate at an 85 percent plant factor to allow for forced outages, maintenance, etc. It is also assumed that full rated capacity will be dependable for meeting critical period peaking requirements.

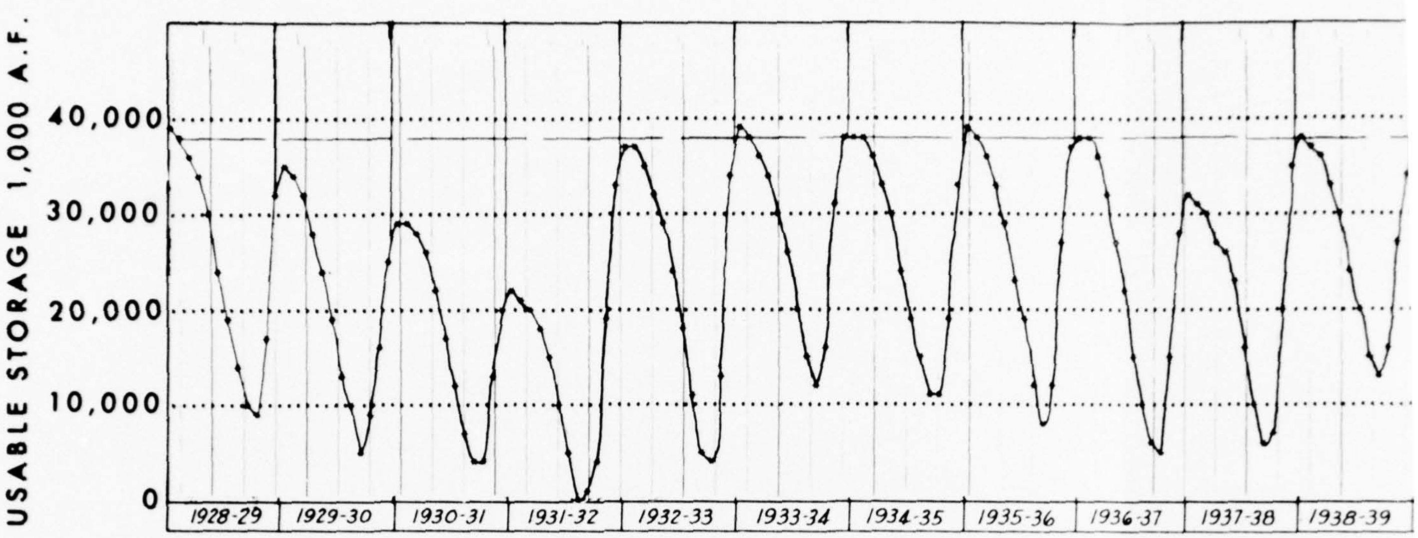
In most years there is sufficient water to permit hydroplants to generate considerable energy in excess of the hydro system prime energy. It is, therefore, assumed that this secondary hydroenergy will be used for the replacement of thermal energy and that when secondary energy is available the thermal plants will be shut down in order of decreasing energy (fuel) costs. The effect this has on thermal plant operation is shown on figure 17. As might be expected, there are certain problems associated with the assumed operation, and actual operational experience will have to be obtained before its practicability can be ascertained. However, in the light of pure economic considerations and the fact that present interutility planning and contractual agreements are currently proceeding on this basis, it is felt that this assumption is valid.

Peaking Plant Operation

By the 1990's, when all of the conventional hydro peaking capacity has been installed, there will be a need for additional capacity to handle the increasing peak load. As discussed earlier, a number of alternatives are available, including pumped storage. Each, by the nature of its operation, is particularly suited for carrying a specific part of the peak load. However, it is impractical to attempt to allocate the peak load among these alternatives 30 to 50 years in advance. Instead, it was considered adequate just to identify the magnitude of the capacity deficit and to assume that it will be allocated appropriately among the alternatives.

Monthly Operation in a Weekly Load Cycle

Electric power conditions are continually changing. In the Pacific Northwest Coordinated System, where a number of plants, thermal as well as hydro, will be involved, well-balanced guide plans for allocation of plant loadings are essential. These guide plans will include daily and weekly, as well as seasonal plans. The load allocation plans should be flexible enough so that each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20,000
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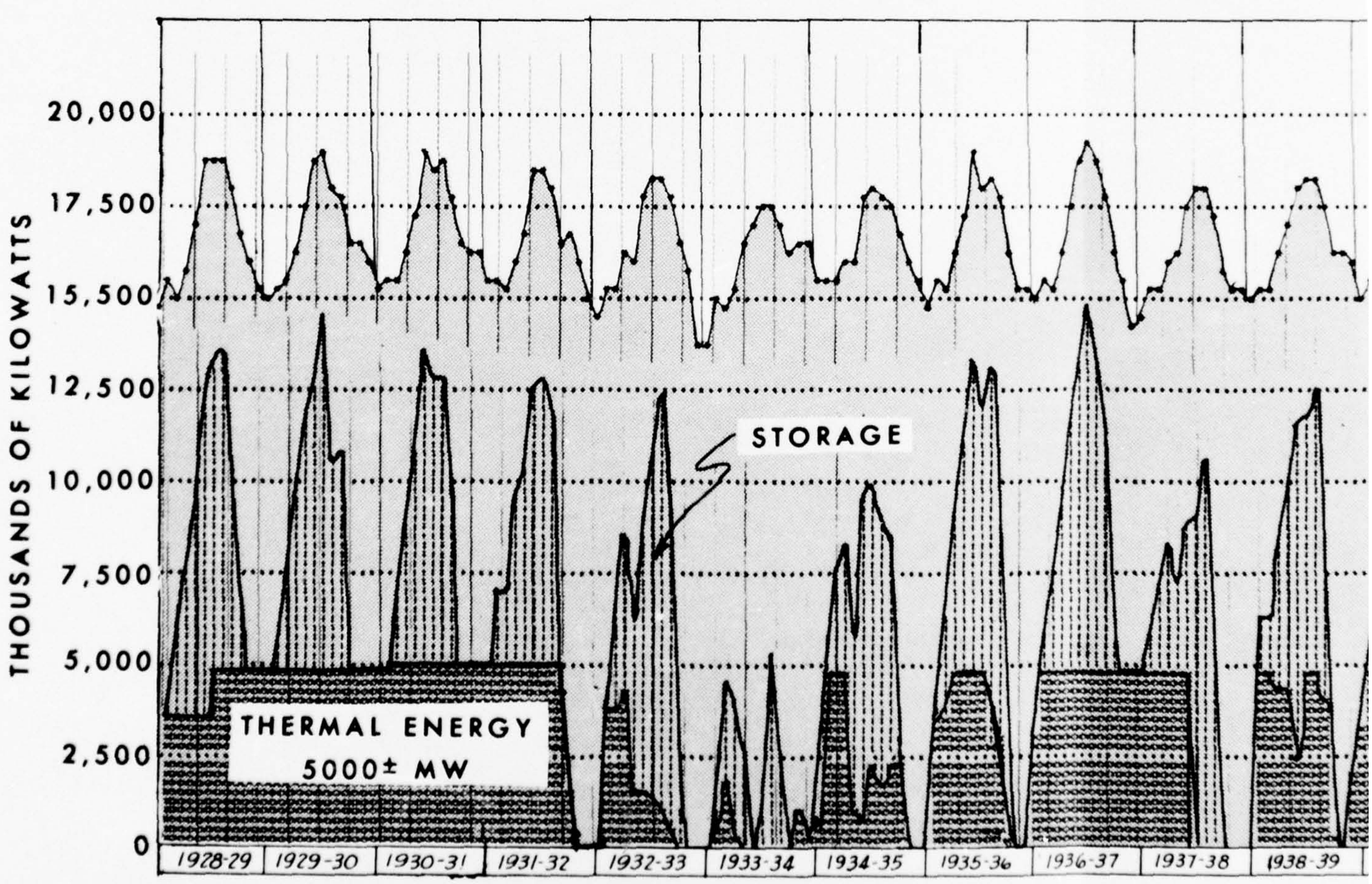
1936-37
1937-38
1938-39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20,000
17,500
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12,500
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7,500
5,000
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STORAGE
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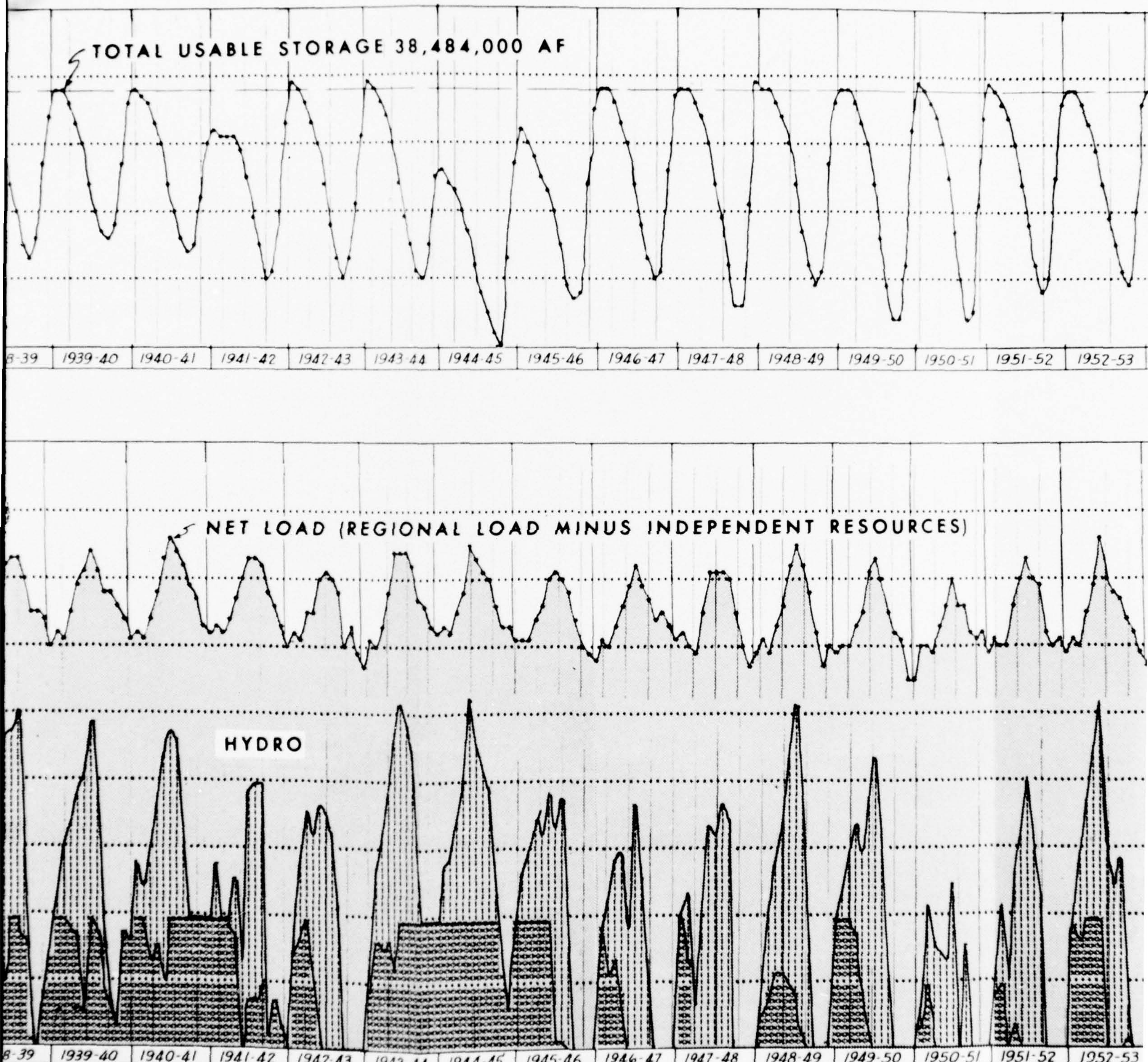

Figure 17. Thermal and Hydro Resour

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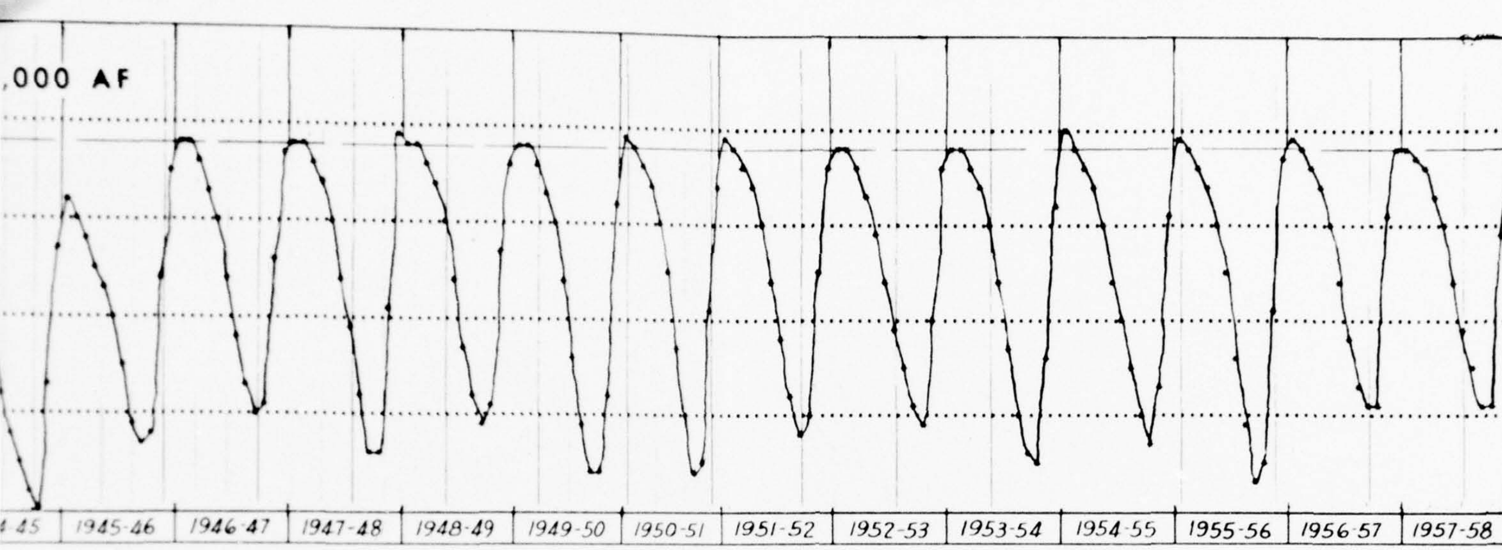

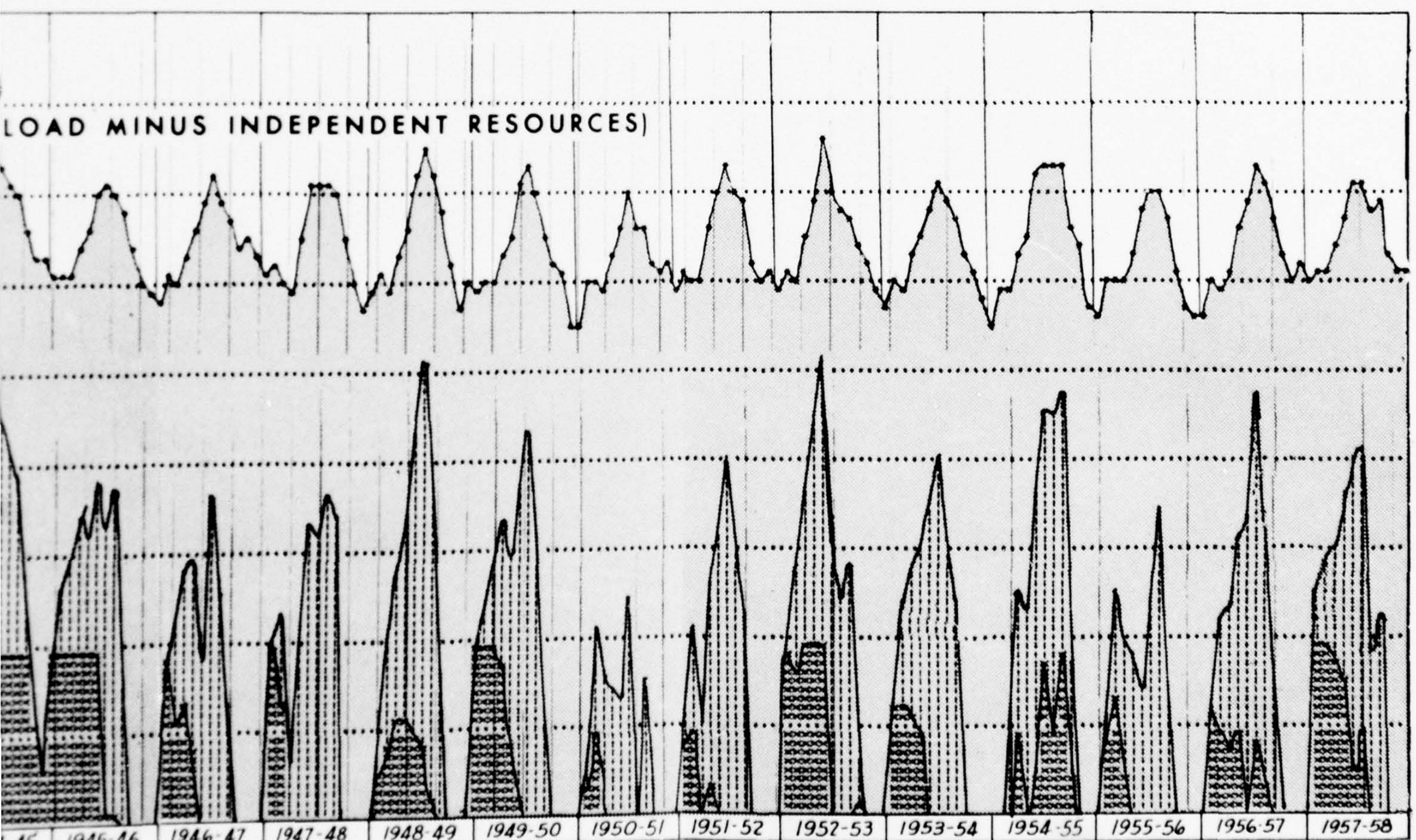

Figure 17. Thermal and Hydro Resources Meeting the Estimated 1980 Load

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individual plant loading can be changed as necessary to obtain the maximum coordinated system generation. Extensive fluctuation of hydroplant loadings and low load factor operation results in higher tailwater elevation and, therefore, reduced head at the time of maximum loading. This type of operation results in less generation at higher heads during the night and more generation at lower heads during the daytime. This combination in turn means less total generation from a given amount of water than would be obtained by a more uniform operation throughout the day or the week. Furthermore, extreme fluctuations may have adverse effects on nonpower water uses such as recreation and fish and wildlife. These adverse effects may be more significant at some times of the year than at others. However, fluctuation of the loads to be carried by thermal plants increases unit production costs. Extensive fluctuations of thermal units not only reduces thermal plant efficiencies but may require spinning standby capacity at night, all of which increases the total system production costs. Extensive and continuing studies based upon accumulative experience will be necessary to obtain the most practical system as a whole within the established constraints.

It can be seen that the additional hydro included in Plan A would not have a very great effect in reducing the base-load thermal requirements, but would have a significant effect on the pumped storage or thermal peaking capacity requirements.

Figure 17 shows graphically the results of a 30-year regulation study at the 1980 level. While this study was not one of those finally adopted for this report, it is typical and illustrates the gradual pulling down of the system reservoirs over the course of the August 1928 through February 1932 critical period as well as the large block of thermal energy required to meet system loads during the critical period.

Summary of Resources

In order to present as wide a range of hydro-thermal system combinations as possible, load-resource analyses were made for two different systems. Plan A is the maximum hydro system and includes all of the hydro projects discussed in the hydroelectric resources inventory except for Penny Cliffs, which is located on an established Wild River. The capabilities of the hydro projects at each level are listed on table 37 and the load-resource analyses summarized on table 39. Plan B is the minimum hydro system and includes only hydro projects which are now existing or under construction. As with Plan A, it includes all authorized and licensed additions to existing and under construction projects. The capabilities of the Plan B hydro projects are listed on table 38 and the load-resources analyses on table 40.

Table 39 - Load Resource Analysis: Plan A[1], Columbia-North Pacific Region

Item	OBERS[2] Population Estimates 1980[4]	2000	2020	Maximum Population Estimates[3] 1980[4]	2000	2020
Energy						
Load	18.2	54.7[5]	125.1[5]	18.2	58.4[5]	146.8[5]
Reserves	0.5[6]	6.9[7]	19.3[7]	0.5[6]	3.2[7]	23.1[7]
Total Load	18.7	61.6	144.4	18.7	61.6	169.9
Hydro Resources	11.9	15.5	15.5	11.9	15.5	15.5
Thermal Resources	6.3	38.1	116.9	6.3	38.5	142.4
Thermal Imports	0.5	8.0	12.0	0.5	8.0	12.0
Total Resources	18.7	61.6	144.4	18.7	62.0	169.9
Peaking Capability						
Load	30.0	84.8[5]	191.7[5]	30.0	91.3[5]	229.4[5]
Reserves[8]	3.8	10.2	23.1	3.8	11.0	27.5
Total Load	33.8	95.0	214.8	33.8	102.3	256.9
Hydro Resources	26.3	56.0	56.0	26.3	56.0	56.0
Base Load Thermal	7.3	38.1	116.7	7.3	38.5	142.4
Thermal Imports	0.2	8.0	12.0	0.2	8.0	12.0
Peaking Resources[9]	0.0	0.0	30.1	0.0	0.0	46.5
Total Resources	33.8	102.1[10]	214.8	33.8	102.5[10]	256.9

1/ Maximum hydro system.
2/ Based on Columbia-North Pacific population forecasts prepared by OBE-ERS.
3/ Same population forecasts as above for 10 of the 12 subregions; population forecasts for Subregions 9 and 11 from the respective Type 2 studies.
4/ Data derived from Pacific Northwest Utility Conference Committee West Group Forecast estimates.
5/ From table 22.
6/ Energy reserves for 1980 based on one-half year's utility load growth.
7/ Fifteen percent of the required thermal capability (including imported thermal).
8/ Based on 12 percent of load. Reserves for 1980 computed using Pacific Northwest Coordination Agreement probability analysis formula.
9/ Pumped storage, gas turbines, or other peaking resources.
10/ Surplus capability resulting from import of thermal energy.

The Independent Resources are not listed individually in the hydro resource tables. For Plan B, the Independent Resource category contains essentially the projects listed in tables 49, 50, and 51. The Plan A Independent Resources include, in addition, the hydro projects listed in the potential hydroelectric resources inventory for Subregions 2, 4, 5, 7, 8, 9, 10, and 11. For further information on the capabilities of the majority of these projects, reference should be made to the Independent Resources Study.(23)

The two plans present the two extremes in the development of the region's hydro potential. In trying to forecast what will actually happen, it is perhaps most reasonable to assume that the actual hydro development will take place at a level somewhere between the two extremes. Such a modified forecast can be anticipated particularly in the early years. Loads and resources shown for 1980 on the tables are, therefore, those which are currently being used in the region for programming. They were arrived at cooperatively by the operating entities but modified by events which took place between cooperative preparation in

Table 40 - Load-Resource Analysis: Plan B[1], Columbia-North Pacific Region

Item	OBERS[2] Population Estimates 1980[4]	2000	2020	Maximum Population Estimates[3] 1980[4]	2000	2020
Energy						
Load	18.2	54.7[5]	125.1[5]	18.2	58.4[5]	146.8[5]
Reserves	0.5[6]	7.5[7]	20.1[7]	0.5[6]	8.2[7]	23.8[7]
Total Load	18.7	62.2	145.2	18.7	66.6	170.6
Hydro Resources	11.9	12.2	12.2	11.9	12.2	12.2
Thermal Resources	6.3	42.0	121.0	6.3	46.4	146.4
Thermal Imports	0.5	8.0	12.0	0.5	8.0	12.0
Total Resources	18.7	62.2	145.2	18.7	66.6	170.6
Peaking Capability						
Load	30.0	84.8[5]	191.7[5]	30.0	91.3[5]	229.4[5]
Reserves[8]	3.8	10.2	23.1	3.8	11.0	27.5
Total Load	33.8	95.0	214.8	33.8	102.3	256.9
Hydro Resources	26.3	36.4	36.4	26.3	36.4	36.4
Base Load Thermal	7.3	42.0	121.0	7.3	46.4	146.4
Thermal Imports	0.2	8.0	12.0	0.2	8.0	12.0
Peaking Resources[9]	0.0	8.6	45.4	0.0	11.5	62.1
Total Resources	33.8	95.0	214.8	33.8	102.3	256.9

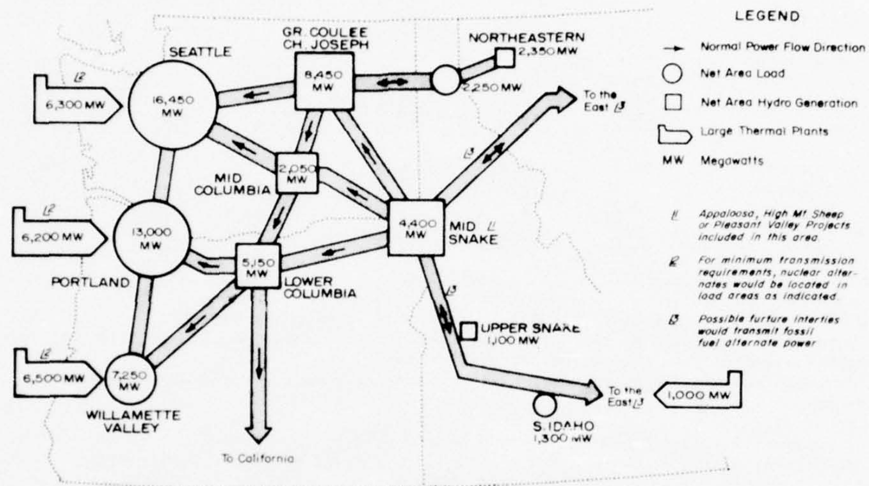
1/ Minimum hydro system.
2/ Based on Columbia-North Pacific population forecasts prepared by OBE-ERS.
3/ Same population forecasts as above for 10 of the 12 subregions; population forecasts for Subregions 9 and 11 from the respective Type 2 studies.
4/ Data derived from Pacific Northwest Utility Conference Committee West Group Forecast estimates.
5/ From table 22.
6/ Energy reserves for 1980 based on one-half year's utility load growth.
7/ Fifteen percent of the required thermal capability (including imported thermal).
8/ Based on 12 percent of load. Reserves for 1980 computed using Pacific Northwest Coordination Agreement probability analysis formula.
9/ Pumped-storage, gas turbines, or other peaking resources.

January 1970 and preparation of the tables. These loads and resources are for the West Group area which excludes much of Idaho and western Montana and, therefore, are not in complete continuity with loads and resources shown for 2000 and 2020 on tables 37 and 38.

PROJECTED TRANSMISSION FACILITIES

Providing sufficient rights-of-way for the transmission of large amounts of power presents one of the biggest problems in meeting power loads of the Columbia-North Pacific Region by the year 2000 and beyond. This will be particularly true for the movement of power from the area east of the Cascade Mountains to the load centers west of these mountains. The major share of the region's power requirements is concentrated in the large population centers of the Pacific slope. This situation is expected to continue throughout the period of this study. A peak load of 13,000 megawatts in 1965 is shown in table 10. Table 23 estimates that this load will grow to 84,800 by 2000, and to 191,700 megawatts by 2020. Local thermal generation will meet most of this increase. However, large-block, extra-high voltage power transmission from other areas will probably supply the remainder.

By 1990 (figure 18, Power Supply and Load Areas and Transmission Routes), when essentially all of the feasible hydro sites in the Northwest will have been developed, loads will have grown to more than triple 1970 levels. This will require additional transmission capacity of more than twice that constructed during the previous 25 years.



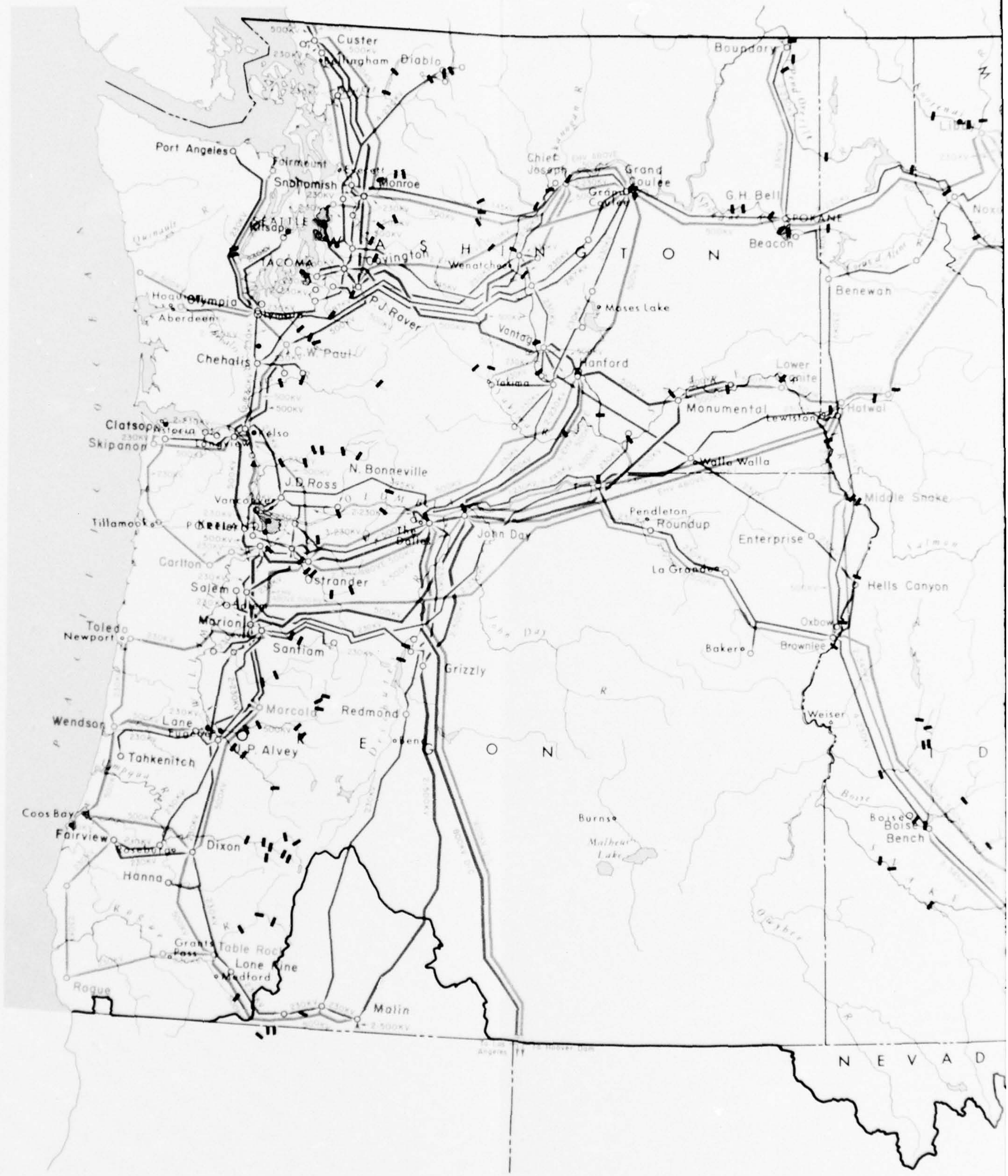
NOTE: Approximately 2500 MW of new thermal on reserve and not included in area totals shown.

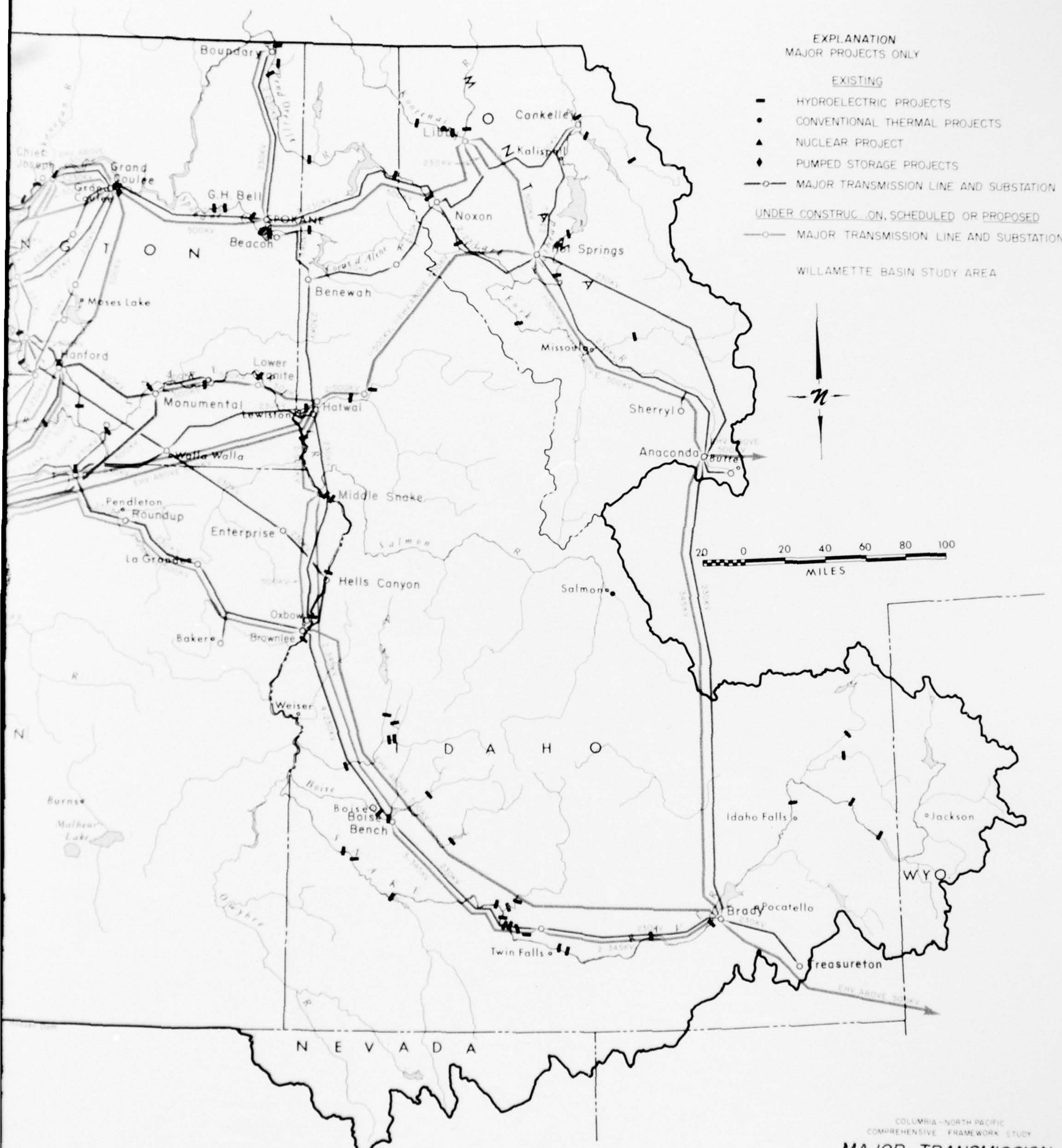
Figure 18. Power Supply and Load Areas, and Transmission Routes – 1990

Although the future periods of 1980, 2000, and 2020 are examined in this framework study, the transmission study was made for the periods 1970 and 1990. The analysis for 1970 is indicative of the existing system, while 1990 represents the limit in time which power utilities have been willing to consider for transmission planning.

Future transmission lines must have markedly greater power transcapacities per right-of-way to reduce their impact on land use and to remain within the limits of available rights-of-way. Increasing transmission voltage levels provide one method of accomplishing this, since line capacity increases approximately as the square of the voltage.

At present, with an essentially all-hydro system, approximately three-fourths of the electric power required for the Pacific slope is transmitted from hydroelectric generation sources east of the Cascades. As the transition to a thermal-electric base progresses, thermal plants located within or adjacent to the load centers will meet more and more of the area's load requirements.


W A S H I N G T O N
O R E G O N
N E V A D
Custer
Bellingham
Diablo
Boundary
Port Angeles
Fairmount
Snohomish
Monroe
Chief Joseph
Grand Coulee
G.H. Bell
Beacon
SEATTLE
Kitsap
TACOMA
Covington
Wenatchee
Olympia
Aberdeen
Moses Lake
P.J. Rover
Vantage
Benewah
C.W. Paul
Chehalis
Hanford
Yakima
Lower Granite
Monumental
Lewiston
Hatwai
Clatsop
Astoria
Kelso
Longview
Skipanon
N. Bonneville
J.D. Ross
Walla Walla
Middle Snake
Tillamook
The Dalles
John Day
Pendleton
Roundup
Enterprise
Carlton
Ostrander
La Grande
Hells Canyon
Salem
Marion
Toledo
Newport
Santiam
Grizzly
Oxbow
Brownlee
Baker
Marcola
Redmond
Weiser
Wendson
Lane
Bend
Tahkenitch
J.P. Alvey
Coos Bay
Fairview
Dixon
Burns
Malheur Lake
Boise
Boise Bench
Hanna
Grants Pass
Table Rock
Lone Pine
Medford
Rogue
Malin
500KV
230KV



MAJOR TRANSMISSION FACILITIES - 1990

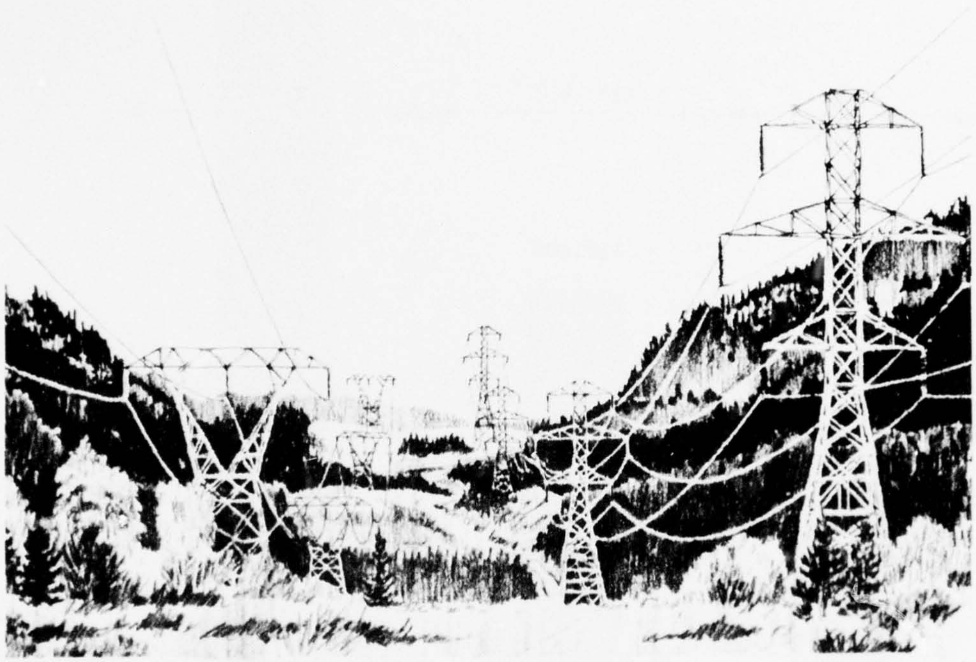
THE REGION

1969

FIGURE 19

2

However, these will be primarily base-load plants, with peak requirements supplied by hydroelectric plants east of the Cascades. This means construction of new cross-mountain transmission lines. Some additional North-South lines will be needed to provide integration and bulk-load power transfers within major load areas and with adjacent load areas. The map "Major Transmission Facilities, 1990" illustrates possible transmission development for the study area by 1990. Present plans call for the construction of several of these lines at voltage levels in excess of 500 kilovolts.



High voltage transmission lines through forest areas require careful planning.

Land Requirements

The land required for electric power transmission has been a problem, not only in areas of concentrated population, but through rural, forested, recreation, and other areas as well. However, as transmission voltages increase, the land use per kilowatt for transmission right-of-way decreases. For example, a 500 kilovolt alternating-current line can carry about five times the power transmitted by a 230 kilovolt alternating-current line, in the order of 1.25 to 1.5 million kilowatts. Yet the 500-kilovolt line requires only slightly more right-of-way; 125 to 150 feet as compared with 125 feet for 230 kilovolts. A comparison of tower sizes, capacities, and right-of-way width requirements for 230, 500 and 700-kilovolt lines is illustrated in figure 20. The bar

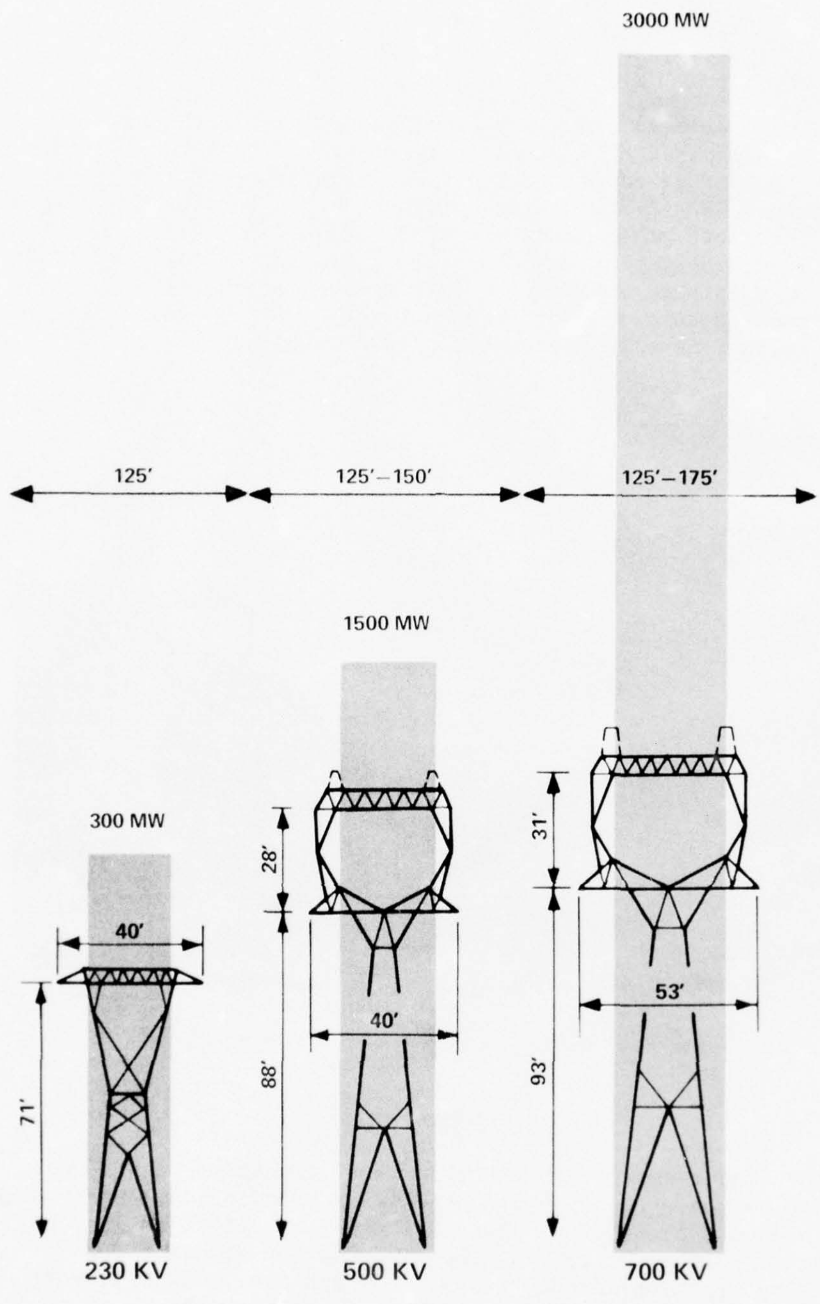


FIGURE 20. Relative Tower Size and R/W Width Compared with Transmission Line Capability

graphs show the considerable increase in transmission capacity per circuit, which can be effected through use of the higher voltages with only a proportionately small increase in right-of-way widths. Analysis of the data given results in the following table, which reflects these increases in terms of megawatts per foot of right-of-way width.

	230-KV	500-KV	700-KV
Width of right-of-way, feet	125	125-150	125-175
Transmission capacity per circuit, MW	300	1,500	3,000
Transmission capacity per circuit per foot of right-of-way width, MW/foot	2.4	10-12	17-24

A study has been made which shows that it would be desirable to replace some of the existing 115- and 230-kilovolt lines with 500- or 700-kilovolt circuits, utilizing the same general right-of-way which would result in reducing the need for new right-of-way.

The most important aspect of this line replacement study is that of replacing existing transmountain lines with these much higher capacity circuits. This will increase east-west transmission capability markedly without the need for developing new rights-of-way through the mountains. The present east-west capability of approximately 8,000 megawatts could be increased upward to about 55,000 megawatts in this way.

Whatever future land requirements may develop, the need for careful placement of transmission corridors in respect to other forms of land use will continue. Planners will route transmission lines through areas so as to result in the least conflict with other land uses. Farm or pasture lands, brush areas, etc., often adapt well for transmission line use with minimum conflict. Also, transmission line planners should consider the esthetic distraction of line locations in certain areas and avoid public recreation areas, main highway routes, or wilderness-type vista areas where possible.

By 1980, there will be in operation some 3,500 circuit miles of 500-kilovolt (or above) lines in the study area. Many of these lines will interconnect the major hydroelectric generating plants and deliver their outputs to the West Coast load centers. Others will be North-South integrating lines, interconnecting the load centers, their primary purpose being to provide continuity of service. A number of the new lines will be routed over existing rights-of-way presently occupied by 115- and 250-kilovolt lines which will be retired.

While replacement of existing lines with higher-voltage, higher-capacity lines will help limit new right-of-way requirements, continually increasing power needs in the major load centers of the Pacific slope will require still more transmission capacity between the large generating complexes east of the Cascades and these areas west of the Cascades. By the fall of 1970, four 500-kilovolt transmountain lines will interconnect these generating plants and load areas, in addition to the existing 230-, 287-, and 345-kilovolt system. However, the long-range outlook indicates the need for added circuits with greater capacities than will be provided by single-circuit 500-kilovolt lines. Clearly, other measures for providing the necessary transmission capacity are required, such as going to higher voltages, double-circuit construction, or even developing new methods of electric power transmission.

Research and Development

Voltage Levels above 500-Kilovolts

One alternative under serious study is that of voltage levels in excess of 500-kilovolts. Several 700-kilovolt class lines are in operation or under construction at the present time in this and other countries. Since a 700-kilovolt line has approximately twice the capacity of a 500-kilovolt line, use of this voltage level as an overlay to the extensive 500-kilovolt grid being developed would reduce the number of circuits required and the impact on land use in the study area.

One rather promising method of increasing transmission capacity is to employ double-circuit 700-kilovolt construction for the new transmountain lines. A double-circuit 700-kilovolt line can be designed for a right-of-way width the same as, or slightly greater, than those occupied by existing 230-kilovolt transmountain lines. The 230-kilovolt line could be replaced by the higher-capacity line with a resultant 15- to 20-fold increase in transmission capacity, from 250-300 megawatts to in the order of 5,000 megawatts.

Studies are also progressing on 1,000 kilovolt transmission facilities. A 1,000-kilovolt line has approximately four times the capacity of a 500-kilovolt line and about the same capacity as a double-circuit 700-kilovolt line.

However, reliability considerations dictate an orderly strengthening of the system (for the Columbia-North Pacific Region at 500-kilovolts) before going to the higher voltage. The higher the line capacity, the greater the shock to the system when that line is lost due to a short circuit or some other contingency.

Underground Cable

The laying of underground cable on existing rights-of-way presents another method of increasing the transmission capacity per right-of-way. Technically, this is feasible but at present is prohibitively expensive, in the order of 10-25 times as costly per kilowatt of power transmitted as standard overhead lines. Research continues, however, since in certain areas--such as large metropolitan centers, underground transmission is the only acceptable method. Here, transmission distances are short, and the increased costs have much less impact than a 100-300 mile transmission distance would impose.

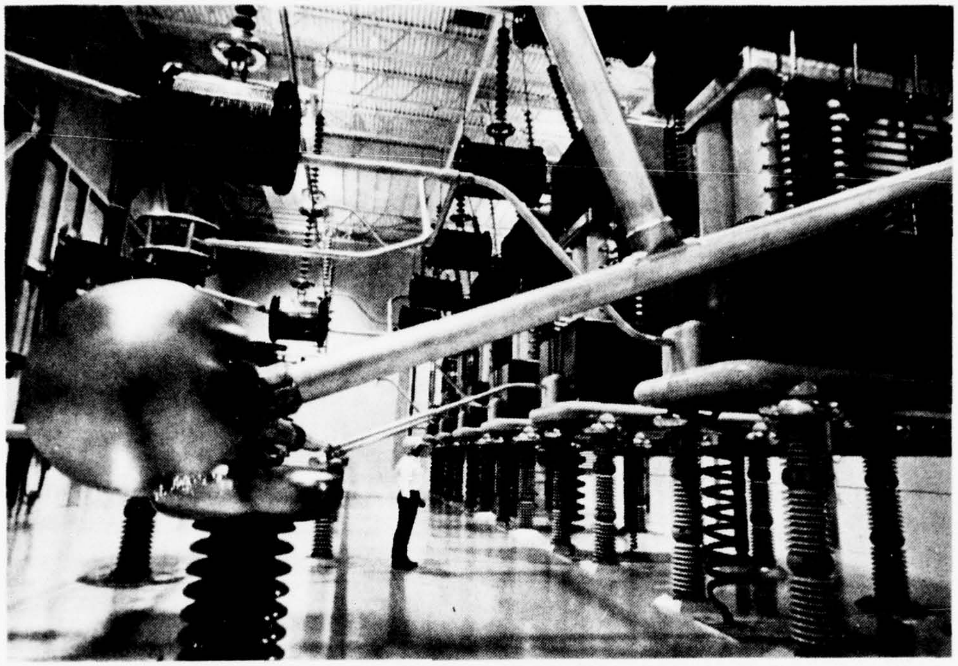
Direct-Current Transmission

Direct-current transmission may be employed for large-block power transfers within the Pacific Northwest in future years. At the present time, direct-current can compete economically with alternating-current transmission only when distances are greater than approximately 500 miles for overhead lines and 30-60 miles for underground cables. Direct-current terminals are quite complex and costly when compared with alternating current substation equipment, but direct-current line costs are only about two-thirds that of alternating current because two conductors rather than three are required. The economic "crossover point" occurs when the difference in line costs equals the difference in terminal costs. Since the transmission distance in the Northwest from point to point for future systems will be less than 300 miles, direct current will not be justified, unless marked reductions in terminal costs are effected. Of course, if other factors require the use of underground cables, direct-current could be very attractive.

Another factor which could influence the use of direct-current transmission is the magnitude of fault duties on terminal equipment as the system grows. As alternating-current facilities are added, short-circuit quantities increase with resultant greater stresses imposed upon circuit breakers and other equipment. This could cause a rather expensive equipment change-out program. The use of direct-current system additions would obviate this need, since fault duties are not increased by the addition of direct-current facilities.

Superconducting Transmission

The cryogenic (extremely low-temperature) field may accelerate the use of direct-current transmission with the development of superconducting cables having many times the



Direct current terminals are quite complex and costly (Bonneville Power Administration).

capacity of conventional lines or cables. By refrigerating the conductors to temperatures near absolute zero, a system can attain an essentially lossless transmission, allowing very high power flows per circuit. Even though the cost per circuit would be high, as would also the reserves necessary, the unit cost per kilowatt transmitted could compare very favorably with more conventional methods of electric power transmission.

Research is progressing in this area, but thus far no significant breakthroughs have resulted. One interesting facet of this program is the goal of developing a material which would have superconducting qualities at normal temperatures. Success in this effort would revolutionize the whole field of power transmission.

Effects of Thermal Plant Location

Thermal plants should, in general, be located adjacent to or near the major load centers to minimize transmission costs--both in facilities required and in transmission losses. However, a number of other factors will also influence plant location, such as environmental, public acceptance, and geologic consideration.

Studies based upon transmission considerations alone have been made for determining the optimum scheduling and location of these plants through the 1990 period. Results indicate that the

preponderance of the thermal plant additions up to this time should be located west of the Cascades and south of the Puget Sound subregion. Power normally flows to the west and south in the western portion of the region. The Portland area is approximately 100 miles farther from the large mid-Columbia generating complex than the Puget Sound subregion. In effect, locating a plant in the Portland area rather than in the Puget Sound area would save approximately 100 miles of transmission line, plus resultant line losses. Therefore, from a transmission standpoint, the desirable pattern of thermal plant locations would maintain low North-South power flows on the coastal grid. Load growth in the Puget Sound region would be met by a combination of local thermal and added hydro installations in the mid-Columbia area. Load growth south of the Puget Sound region would be met primarily by local thermal with some peaking supplied by hydro from east of the Cascades. This is illustrated in figure 18. This pattern would continue until essentially all of the Northwest hydro sites are fully developed, at which time thermal plant siting would follow load growth.

Some of the new thermal installations will no doubt be located east of the Cascades for reasons other than those related to transmission requirements, such as the economies of scale in developing large complexes and greater public acceptance of locating nuclear plants away from major population centers. This would require an earlier development of increased transmission capacity through the mountain passes and alter the distribution illustrated in figure 18.

SITE SELECTION OF THERMAL-ELECTRIC PLANTS

Having identified the required thermal-electric capability at the three target levels of development, it is necessary to locate this capability before its impact on specific water supplies can be estimated. The locations result from the interplay of many tangible and intangible factors. These include the influence of regulatory agencies, availability and cost of land, site preparation costs, cost of transmission, as well as availability of cooling water, which is the subject of principal concern for this report. All these factors and many others determine the public opinion regarding a site selection which in the end determines whether a given site is used.

The general interrelation between site selection factors follows the report Considerations Affecting Steam Power Plant Site Selection (17). More specific information for site selection has been provided by the report Nuclear Power Plant Siting in the Pacific Northwest (2). Data from these reports are supplemented by other available data for fossil-fuel fired, thermal-electric plants where these are more likely in certain parts of the region.

Site Location Factors

The site location factors are discussed in further detail in the following sections.

Transmission

The cost of power transmission from a generating plant is in many cases the cost factor which bears the greatest relation to location. Both the capital cost and the thermal loss of the line are dependent on distance. It follows then that thermal generating plants will be located as close to load centers as other distance-related factors will permit. Application of this simple rule is complicated by the fact that many new generating plants of today are cooperative enterprises designed to serve the loads of several or many utilities. The economics of larger size units will tend to increase these cooperative enterprises. In addition, the present trend in utility operation is toward a much higher degree of interutility coordination than has been employed in the past. Thermal generation in the region will accordingly require transmission facilities considerably more extensive than have been exhibited by thermal based systems in the past.

Heat Dissipation

The present day large nuclear-electric generators waste approximately two-thirds of the heat which they produce. A 1,000-megawatt light-water reactor accordingly produces about 3,070 megawatts of total heat on the present basis of 32.6 percent thermal efficiency. The higher operating temperatures permitted by a gas-cooled reactor and subsequently by a breeder reactor will raise this efficiency to slightly over 40 percent, the same efficiency afforded by a conventional fuel-fired plant. It appears that nuclear plants having the improved efficiencies will be available well before the year 2000.

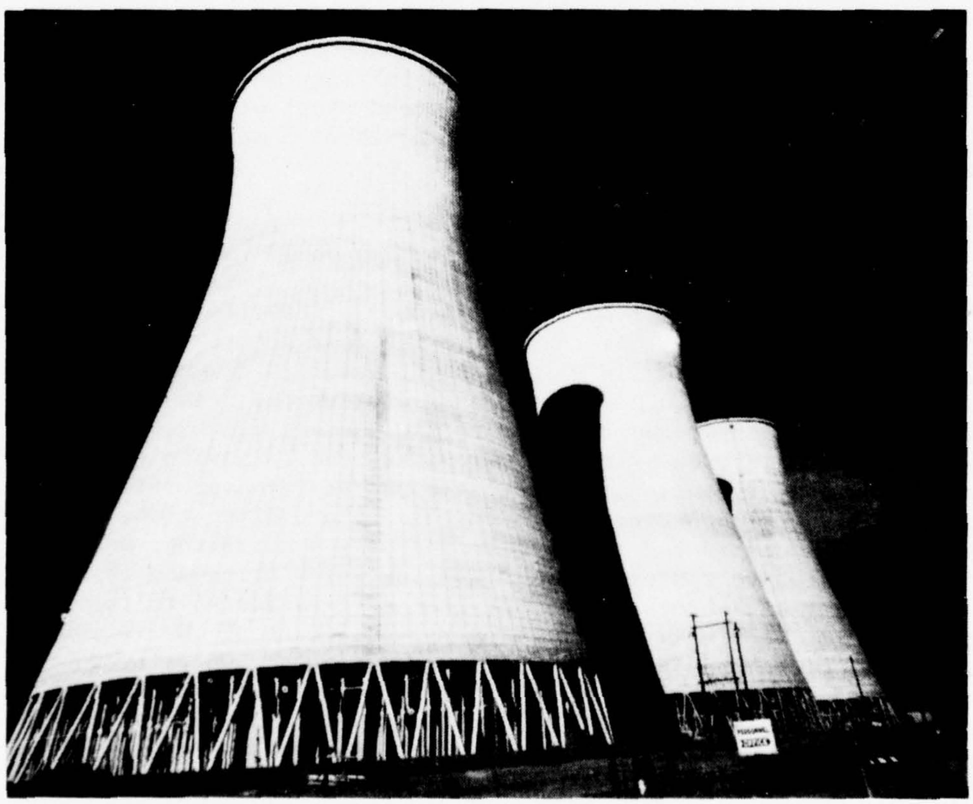
Present day nuclear powerplants generally have a condenser effluent temperature slightly in excess of 90°F. Although there are large amounts of such heat to be wasted, this is too low a temperature to be attractive for most by-product uses. Research into these uses is underway in the Pacific Northwest, but most such uses provide an alternative method for dissipating heat rather than an actual use of the heat itself.

There are several methods of dissipating heat from a thermal-electric plant. For a given site the method will depend upon cost of land, availability of water, competing water uses, weather conditions, and the economic penalties imposed in the plant itself by less than

ideal cooling methods. A major factor is the limit to increases in water temperatures imposed by regulatory agencies.

The various Pacific Northwest States have adopted standards for quality of water. Among these standards are the limitations upon the heat which is dissipated to water bodies. The standards differ between states but all are generally similar in the restriction which they provide.

Adoption of these standards has the effect of essentially eliminating any once-through cooling of thermal-electric plants on the Lower Columbia River. Cooling towers have been selected for the one generating plant which is underway and presumably such installation will be extended to all such plants of the future. Extending this limitation to other water bodies controlled by the state water quality standards will severely curtail if not eliminate once-through cooling.



With a cooling tower waste heat is dissipated to the atmosphere by evaporation (Paradise plant of Tennessee Valley Authority).

Salt-Water Systems

Cooling with salt water is essentially the same as with fresh water, but there are important economic differences. Water temperatures are low and fairly constant on the coasts and estuaries of Oregon and Washington. The low temperature provides a cost advantage, as less water need be pumped to effect a given amount of steam condensation. Efficiency might be improved because of the lower turbine back pressure. In addition, sites on Puget Sound and the Strait of Juan de Fuca offer several other advantages. Deep water close to shore will permit maximum use of thermal stratification to avoid recirculation. Strong currents carry away and distribute the effluent at a maximum rate. Sheltered locations provide maximum protection against storms and tidal waves. On the open coast, on the other hand, shallow water will necessitate outfall lines long enough to obtain adequate depth for complete mixing of the heated discharge.

Salt-water cooling requires corrosion resistant materials for all water handling facilities. Marine bronzes have the necessary corrosion resistance but are objectionable where any fishery is involved. Copper alloys are toxic to some species; and, where they are not, may result in unpalatability because of discoloration. In such instances stainless steel or nickel-chrome alloys may be necessary at an increase of about 2 percent in the capital cost of condenser tubing.

Alternative Cooling Methods

Although available cooling methods, if identified in detail, would be many, all fall into the following four general classes: (1) once-through cooling in which cooling water is drawn from a large body of water, such as a stream, lake, or the ocean passed through the condenser and returned to the source; (2) a cooling pond which is a closed system in which the pond is sufficiently large to dissipate the heat to the atmosphere; (3) evaporative cooling in which the water is passed through a cooling tower where waste heat is dissipated to the atmosphere by evaporation; and (4) a dry exchange system in which cooling water is passed through a finned heat exchanger where waste heat is transferred to the atmosphere convectively without evaporation. Each of the various methods is preferable under certain circumstances. Once-through cooling has minimum cost and low consumptive use but has a high total water use and adds heat to the waterway. A dry exchange system has minimum water use but has the disadvantage of maximum cost by a large margin. A cooling pond for a large plant requires a very large area. Evaporative cooling, in general represents a compromise among these disadvantages.

For direct cooling, a 1,000-megawatt nuclear plant dissipating some 7 billion Btu per hour, about 1,600 cubic feet per second, might be required for a coolant temperature rise of 20°F. For most evaporative systems a 1,000-megawatt nuclear plant may have an average requirement of 25 to 100 second-feet, as compared to the 1,600 second-feet for direct cooling.

Despite the advantages of evaporative cooling, the disadvantages are significant. Evaporative cooling requires an increased capital investment, and added pumping costs for recirculating the condensate may be large. There will be the additional cost of treating the recirculated cooling water (not to be confused with condenser water) and the cost of power for driving forced draft cooling fans except where natural draft cooling towers are used. In addition, evaporative cooling will usually result in higher condenser temperatures than once-through cooling. The higher temperature will decrease efficiency of the turbine with the result of a reduced capacity.

Although the water demands are much smaller than with once-through cooling, the consumptive use is higher. This disadvantage is serious in some areas as it puts the plant in a competitive position with other important water uses sucn as irrigation and municipal water supply. Even where there is water for the necessary increment of consumptive use, legal difficulties and the cost of quieting competitive claims to water may be serious.

There may be further objections to cooling towers on the basis of esthetics. As natural draft towers are very large they locally dominate the landscape. Whether they are an esthetic asset is a matter of taste, but they will undoubtedly be objectionable to some. Forced draft cooling towers are not as high but they are still quite large and may require special design for the supression of the noise associated with large fans. The cooling tower also produces condensation downwind from the plant. More recent designs have eliminated precipitation from this "plume" and good design keeps the "plume" above ground level. There is still the apperance of the plume to consider, however.

Evaporation of the circulating water causes a build-up of the solids in the water, both natural salts and added chemicals. To limit the build-up, water must be bled from the system in an amount up to 4 second-feet for a 1,000-megawatt plant. Disposal of this blow-down must be effected without pollution of the local streams or ground water.

At sites with available land and favorable terrain cooling ponds may be considered. The pond may be enclosed by earth dikes on flat land, or may be a conventional reservoir or an existing lake. A pond to serve a 1,000-megawatt nuclear plant would require

a surface area of about 2,000 acres and a depth of 15 to 20 feet. The required area will be defined more exactly by climatic conditions.

A cooling pond must be sized to dissipate not only the heat from the condenser, but also solar heat received by the pond. For a pond to serve a 1,000-megawatt plant, the solar load may exceed that imposed by the plant. Water supply must also provide for any necessary seepage loss. The solar effect will, in warm summer weather, approximately double the consumptive use of water as compared to a cooling tower.

Thermal Plant Location

The location of thermal plants as well as their magnitude is essential to definition of their effect on water management. Thermal-electric capability in an area is equal to electric load in the area minus imports and minus local hydroelectric capability. The imports depend upon similar comparisons for other areas, however. Consequently, any one set of loads and hydro capabilities can be compatible with a multitude of thermal site locations. Thermal site locations, therefore, depend upon other future conditions which may be difficult or impossible to predict for as far in the future as 2020 or even 2000. Alternative estimates may furthermore only sample a few of the credible alternatives.

As essentially all the water use for thermal-electric generation is by base energy producing plants, no attempt is made at this point to identify the limited thermal peaking capability located at load centers. The magnitude of such capability will be reduced to the extent that peak load can be carried by maximum hydro peaking capability and by pumped storage hydroelectric plants.

Assumptions for Plant Siting

The foregoing discussion brings out the complex interplay among the factors involved in thermal plant location. Undoubtedly there are additional siting factors which cannot be presently foreseen. What is more difficult to project, however, is the comparative strength of influence of these various factors. Events of the past 2 years, as brought out previously herein, have considerably modified forecasts of plant siting. Recent investigations under the FPC National Power Survey (10) and also by representatives of regional nonpower agencies (50) reveal problems and opportunities heretofore unforeseen. It is reasonable to presume that further unforeseen events in the next few years can effect similar changes in the forecast. Nevertheless, a forecast of water use for power is required at this time.

The basic assumption in thermal plant location is that the thermal plants will supply the electric power loads which the hydroelectric plants are unable to supply. It is further assumed that base electric energy requirements will continue to be provided by nuclear and conventional generating units of the sort existing or in the advanced planning stage today. Although the cost of transmission is a major economic plant location factor, problems of location are too great to confine all thermal generation to the subregions where it will be used. It is not contemplated, however, that any major share of the region's thermal power can be moved great distances. Direct cooling for this study is assumed to be unacceptable, except for salt-water cooling and for special circumstances where the water need not be returned directly to the waterway.

Recognition that the various assumptions in plant location may be invalidated by future economic facts lends support to instituting of the study of alternative thermal plant locations. As described in previous sections of this appendix, alternative load estimates have been identified for the Puget Sound and Willamette subregions, and two alternative future hydroelectric systems have been defined. These then provide four regional alternatives for any given future load level. Location of thermal power in both these subregions has met with considerable resistance, whereas there has been indication that thermal plants in the subregions to the east might be more locally acceptable. Thermal plant location alternatively east of the Cascades provides two more alternatives which combined with the four already defined provide eight alternative thermal plant systems for the region. Other additional alternatives could, of course, be studied as description of the subregions will suggest.

Location of Load

In the electric load estimates previously reported for this appendix no distinction was made as to where in the region these loads were located. For identifying cooling water requirements, however, it is necessary that these loads be located. These locations are specified on table 41 for the loads estimated for the years 2000 and 2020. Thermal plant locations for the 1980 system are for the most part already identified by present utility plans.

The load areas on table 41 refer to boundaries identified with service areas of utilities, as it is the utilities themselves that estimate the load. Exceptions are Areas C and G, Willamette Basin and Puget Sound, for which Type 2 basin investigations have been completed. The correlations between load areas for power purposes and Columbia-North Pacific subregions are shown by

Table 41 - Allocation of Electric Power Requirements by Designated Sub-Areas, Columbia-North Pacific Region

Load-Area1/	2000 Peak	2000 Average	2020 Peak	2020 Average
	(megawatts)			
A.2/	1,500	1,200	2,600	2,200
B.	1,900	1,380	3,300	2,800
C.	27,300	15,520	81,700	46,430
D.	4,500	3,300	7,300	6,100
E.	800	600	1,400	1,100
F.	8,200	6,030	13,500	11,100
G.	21,600	12,530	51,200	29,700
H.	11,100	8,200	17,900	14,930
I.	2,100	1,600	3,400	2,800
J.	5,800	4,300	9,400	7,900
Total	84,800	54,660	191,700	125,060

Substantial differences exist in population projections for sub-areas C and G. Electric power estimates for the region with alternate higher population projections in the Puget Sound and Willamette subregions would be as follows:

	2000 Peak	2000 Average	2020 Peak	2020 Average
	(megawatts)			
C.	27,300	15,520	91,800	52,170
G.	28,100	16,270	78,800	45,700
Total	91,300	58,400	229,400	146,800

1/ See figure 21 for boundaries.
2/ Estimates may prove conservative considering phosphate industry growth potential in sub-area A.

figure 21. In approximate terms, however, the correlations are as follows:

Load Areas	Subregions
A	4
B	5
C	9
D & E	10
F	8
G	11
H	3, 7, & 12
I	2 & 6
J	1

Transmission Limitation

Import of thermal power to the Willamette and Puget Sound subregions appears feasible within certain limits. Some power may be imported from coastal locations, but these will be limited by availability of sites. Import from the East may be acceptable up to the capacity of existing transmission corridors. This capacity

COLUMBIA-NORTH PACIFIC
COMPREHENSIVE FRAMEWORK STUDY

LOAD AREAS
THE REGION
1969

FIGURE 21

will be increased by higher transmission voltage; but it seems improbable that additional corridors will be acceptable, as there are important competing land uses. Transmission studies indicate an east to west limitation of roughly 22,000 megawatts north of the Columbia River and 33,000 megawatts south of the Columbia. Future studies will undoubtedly define this limit more precisely. This limit south of the Columbia is 30,000 megawatts in addition to an estimated import of 3,000 megawatts from the Klamath River Basin outside the region by 2020. The effect of these limitations is illustrated for the year 2020 for one of the eight alternatives on table 42. As shown, Area H exports 30,000 peak megawatts and Area I, 26,100 peak megawatts, of which detailed computation shows only 22,000 megawatts are west to Area G. Considering the entire area east of the Cascades, export to the west is the limit of 52,000 peak megawatts derived as follows:

Hydro capability	32,800 megawatts
Thermal import	9,000
Thermal capability	51,200
Load plus reserve	-41,000
Export to the west	52,000 megawatts

In addition to the 52,000 megawatts imported from the east on table 42, 10,000 megawatts are assumed to be imported from coastal locations to each of the Willamette and Puget Sound subregions. This leaves a required thermal peak installation of 50,300 megawatts in the Willamette Subregion and 24,200 megawatts in the Puget Sound Subregion. Thermal peaking requirements are also derived on the table for the other load areas.

Table 42 - Requirement for Peaking Capacity - Columbia-North Pacific Region
Minimum Hydroelectric System - OBERS Population Forecast
Minimum Western Thermal - 2020 Loads and Resources

Load Area	East or West	Peak Load	Load Plus Reserve	Peak Hydro	Net Peaking Requirement: Total Req.	In Area	Area Exchange	Thermal Import
				(millions of kilowatts)				
A.	E	2.6	2.9	0.3	2.6		0.6	2.0
B.	E	3.3	3.7	1.6	2.1		1.1	1.0
C.	W	81.7	91.5	1.2	90.3	50.3	40.0	
D.	W	7.3	8.2	0.3	7.9	14.9	(10.0)	3.0
E.	W	1.4	1.6	0.0	1.6	11.6	(10.0)	
F.	W	13.5	15.1	0.9	14.2	14.2		
G.	W	51.2	57.4	1.2	56.2	24.2	32.0	
H.	E	17.9	20.1	10.1	10.0	40.0	(30.0)	
I.	E	3.4	3.8	18.7	(14.9)	11.2	(26.1)	
J.	E	9.4	10.5	2.1	8.4		2.4	6.0
Total		191.7	214.8	36.4	178.4	166.4	0.0	12.0
	W	155.1	173.8	3.6	170.2	115.2	52.0	3.0
	E	36.6	41.0	32.8	8.2	51.2	(52.0)	9.0

Location of Thermal Electric Capability

The thermal plant installation required for energy in each load area is the energy load divided by 0.85 plant factor after substraction of hydroelectric energy resources. This plant factor is in recognition of maintenance, refueling, and unscheduled outages. This installation is shown on table 43 for the same alternative for which thermal peaking installation was shown. The other seven alternatives were similarly derived for all load areas. Shown with this installation is the required peak capacity from table 42. As shown, all the thermal installation in central Oregon and Washington will be used to generate energy, but the installation for peaking will be considerably greater than the installation for energy in the Willamette and Puget Sound load areas. A part of this excess could be supplied alternatively by pumped storage.

Table 43 - Projection of Thermal Plant Installation - Columbia-North Pacific Region
Minimum Hydroelectric System - OBERS Population Forecast
Minimum Western Thermal - 2020 Loads and Resources

Load Area	Energy Load	Hydro Energy Capability	Thermal Requirement for Energy		Required Peak	Installation for Energy		Subregion No.
			Energy	Plant Size		Load Area	Subregion	
				(millions of kilowatts)				
A.	2.2	0.2	2.0	2.4	0.0	0.0 1/	0.0	4
B.	2.8	0.6	2.2	2.6	0.0	0.0	0.0	5
C.	46.5	0.6	45.9	54.0	50.3	17.6	21.0	9
D.	6.1	0.2	5.9	6.9	14.9	13.9 2/	25.0	10
E.	1.1	0.0	1.1	1.3	11.6	11.3	13.0	8
F.	11.1	0.4	10.7	12.6	14.2	12.6	16.0	11
G.	29.7	0.5	29.2	34.4	24.2	14.4	0.0	3
H.	14.9	3.4	11.5	13.6	40.0	40.0 3/	37.0	7
							0.0	12
							9.0	2
I.	2.8	5.8	(3.0)	(3.5)	11.2	11.2 3/	0.0	6
J.	7.9	0.5	7.4	8.7	0.0	0.0 4/	0.0	1
Total	125.1	12.2	112.9	133.0	166.4	121.0	121.0	

1/ Excludes 3.0 gw imported from east of region.
2/ Excludes 3.0 gw imported from Klamath Basin.
3/ Limited by transmission.
4/ Excludes 6.0 gw imported from outside the region.

Shown adjacently on the table are the subregions most closely corresponding to each load area. Although there is a lack of exact correspondence, the location of thermal capability by subregions is apparent when the characteristics of these subregions are considered.

To keep the alternatives which are reported within a reasonable number, some comparatively arbitrary assumptions need to be made. The assumption that 10,000 megawatts of thermal capability will be imported to each of the Willamette and Puget Sound subregions from coastal locations has been described. In recognition of the economical supplies of fossil fuels, it was assumed that there would be imported the energy shown by the footnotes on table 43 from sources outside the region. Alternatively,

importation of the fuel, particularly into Subregion 1, is a possibility which would be considered if unlimited alternatives were being studied.

Although Subregion 2 has a surplus of hydroelectric capability for its own needs, it provides a location for minimizing thermal installation in the Puget Sound Subregion, within the limit of transmission capacity. For other alternatives, a minimum capability of 2,000 megawatts, including the existing Hanford thermal plant through 2000, with direct cooling is located within the subregion in recognition of possibilities for combining thermal generating capacity with irrigation development.

Subregions 1, 4, and 5 are shown without thermal capability because of their coal-fired imports. Before 1980, Idaho Power Company plans to import power from Jim Bridger powerplant located just east of the subregion near a large coal deposit. Subregion 12 is expected to have no thermal capability because of its extremely small load. Subregion 3, the Yakima River Basin, is assumed to have no thermal capability because of the high alternative value of cooling water for irrigation. Coal deposits exist in this subregion, however, and an alternative which considers some thermal capability would have some support. Subregion 6, Lower Snake, is expected to have no thermal capability because of light load and high hydroelectric capability which would provide a surplus at all three levels of development.

Subregion 7, Mid-Columbia, because of its cooling water supply, will have a high thermal capability. This capability is particularly high in alternatives where there is a maximum transmission of power to the Willamette Subregion.

WATER REQUIREMENTS AND MANAGEMENT NEEDS FOR POWER

Electric Power relates to the regional plan of water resource development through the water requirements for driving and cooling generating plants. These needs are derived from the location and mode of operation of hydroplants and the type and location of thermal-electric plants in the region. With the power resource requirements developed in the preceding sections, it is possible to derive water requirements and management needs for power.

Water Requirements for Thermal Power

Thermal plant installations projected on table 43 are interpreted in terms of cooling water needs by application to these installations the rate of cooling water use by the various projected types of plants.

Rate of Water Use

In view of the several alternative methods of cooling, it is best to simplify the requirements somewhat for identification of future water requirements. Certain minimum distinctions are necessary, however. There is a large difference in water requirements between direct cooling and evaporative cooling. The difference extends to both the magnitude of water use and to the degree to which each is a consumptive use. There is also the need to recognize the improved efficiency in use of water, which will result with conventional thermal generation or advance type reactors. With these distinctions in mind, the water uses shown on the following table were adopted for computation of basin water use for power.

Table 44 - Cooling Water Requirements, Cubic Feet per second per 1,000 megawatts with 20°F. Temperature Rise

	Light Water Reactors		Conventional Thermal Plants & Advanced Nuclear Reactors	
	Direct	Evaporative	Direct	Evaporative
Circulating Requirements	1,620.00	-	1,185.00	-
Consumptive Use	0.40	34.3	0.40	27.5

Subregional Requirements

As a distinction in use of cooling water is made between four different types of plants, these types must be identified at the various levels of development. Generally, it is recognized that the advanced nuclear reactors will not be available in 1980, but should be fully available by 2020. In the year 2000, some of the light water reactors will still be in service. Computations also need to reflect the limited amount of direct cooling which is anticipated in some subregions.

The computed water requirements for thermal-electric generation are summarized on table 45 for all eight of the alternatives studied. Subregions 1, 3, 4, 5, and 6 are excluded because, as previously described, they are expected to have no thermal generating capability. The amounts shown are average use, as at times of peak load use would be somewhat greater. Although eight alternatives and three levels of development are shown, they still do not arrive at the depletion of any specific stream. In some instances, the alternatives within a subregion are limited; but, for most, a number of plans would have the forecasted use. There, furthermore, remains the problem of which the eight alternatives should be recognized in subsequent studies of nonpower use. One alternative, such as minimum hydroelectric installation, with maximum thermal installation east of the Cascades and maximum loads in Subregions 9 and 11, could be selected. Such further refinement is a plan formulation activity.

Table 45 - Summary of Water Use for Thermal Electric Generation, Columbia-North Pacific Region

Sub-region 1/	Maximum Thermal Installation West of the Cascades: Maximum Loads in Subregions 9 and 11: Maximum Hydro Capability 1980	2000	2020	Minimum Hydro Capability 1980	2000	2020	Consistent Loads in All Subregions: Maximum Hydro Capability 1980	2000	2020	Minimum Hydro Capability 1980	2000	2020
						(Cubic Feet per Second)						
2	0.3	0.7	16.9	0.3	0.7	24.2	0.3	0.7	16.9	0.3	0.7	24.2
2/	1,400.0	2,900.0	1,800.0	1,400.0	2,900.0	2,800.0	1,400.0	2,900.0	1,800.0	1,400.0	2,900.0	2,800.0
7	0	0	205.7	0	0	233.8	0	0	203.4	0	0	233.8
8	64.8	174.1	314.9	64.8	174.1	314.9	64.8	174.1	314.9	64.8	174.1	314.9
9	32.1	277.7	1,220.1	32.1	370.1	1,266.2	32.1	286.0	1,058.7	32.1	383.5	1,103.2
10	0.4	2.5	8.6	0.4	2.5	8.6	0.4	2.5	8.6	0.4	2.5	8.6
3/	1,500.0	8,800.0	27,000.0	1,500.0	8,900.0	27,000.0	1,500.0	8,800.0	27,000.0	1,500.0	8,900.0	27,000.0
11	0.4	4.1	1,028.9	0.4	5.5	1,041.7	0.4	3.8	587.8	0.4	3.9	597.0
3/	0	14,400.0	0	1,500.0	18,800.0	0	0	13,600.0	0	1,500.0	13,500.0	0
						Minimum Thermal Installation West of the Cascades						
2	0.3	0.7	16.9	0.3	49.8	234.6	0.3	47.2	350.9	0.3	0.7	218.2
2/	1,400.0	2,900.0	1,800.0	1,400.0	2,900.0	2,900.0	1,400.0	2,900.0	2,800.0	1,400.0	2,900.0	2,800.0
7	0	406.9	593.8	0	396.4	1,001.0	0	265.0	660.0	0	417.4	997.6
8	64.8	174.1	314.9	64.8	174.1	314.9	64.8	174.1	314.9	64.8	174.1	314.9
9	32.1	84.0	967.8	32.1	134.3	575.6	32.1	134.3	652.2	32.1	134.3	418.4
10	0.4	2.5	8.6	0.4	2.5	8.6	0.4	2.5	8.6	0.4	2.5	8.6
3/	1,500.0	8,800.0	27,000.0	1,500.0	8,900.0	27,000.0	1,500.0	8,800.0	27,000.0	1,500.0	8,900.0	27,000.0
11	0.4	1.4	918.7	0.4	2.8	793.0	0.4	1.7	193.4	0.4	1.7	353.6
3/	1,500.0	4,800.0	0	1,500.0	9,800.0	0	1,500.0	6,100.0	0	1,500.0	6,100.0	0

1/ Subregions not shown have zero water requirements.
2/ Circulating water requirements with fresh water.
3/ Circulating water requirements with salt water.

Regulated Columbia River Flows

In terms of water requirements, a hydro project uses virtually all of the streamflow passing the site. However, hydro is generally classified as a nonconsumptive water use, and with the exception of reservoir evaporation losses, the streamflow thus used is fully available for further use downstream. Increased irrigation depletions and other consumptive water diversions will in time reduce somewhat the amount of streamflow available for hydro generation, and this factor has been accounted for in the system regulation studies. However, the objective of hydroelectric system operation will continue to be to use, when possible, all of the available streamflow for energy generation. Thus, the most important consideration with respect to hydro is water management rather than quantitative water requirements. The following paragraphs dwell primarily on this problem of effective management of the existing water resources for hydropower generation and the effect it will have on streamflow.

With the completion of the Columbia River Treaty Projects, a substantial amount of storage will have been added to the system for regulating the seasonally fluctuating natural streamflow of the Columbia River. In addition, pondage is available at the run-of-river projects for effecting short-term (hourly, daily, and weekly) regulation. While the seasonal regulation for power is generally compatible with operations for flood control, irrigation, and navigation, it is constrained to some degree by the requirements of recreation and fish. Short-term regulation is constrained somewhat by the need to maintain minimum releases for water quality, navigation, water rights, and fish and wildlife, and to limit fluctuations in river and pool levels. These constraints are necessary to attain the overall objective of optimum multiple-purpose use of the flow of the Columbia River. Within these constraints, the available storage will be used for the optimum generation of power at the storage plants and the mainstem run-of-river plants.

Monthly Streamflow Fluctuation

The average unregulated monthly streamflow at The Dalles ranges from a maximum of over 400,000 cubic feet per second in May and June to less than 100,000 cubic feet per second from October through February. Existing storage projects, excluding the Columbia River Treaty Projects, have made it possible to store part of the early summer peak flows to be used for power generation in the winter months. By 1980, with the Canadian Columbia River Treaty Projects plus the Libby and Dworshak reservoirs in operation, it will be possible to regulate streamflow in such a manner that most monthly flows will range between 100,000 and 200,000 cubic feet per second, with the minimum generally occurring in the early

fall, following the spring freshet but preceding storage releases to meet the high winter power loads. The extent of regulation with the 1980 system under 1980 monthly loads and depletions is illustrated by figure 22 and the effect that this storage has on the future distribution of monthly flows is illustrated by figure 23. Compared to 1980 conditions, a somewhat wider range of flows will be experienced in 2020 due to the change in the proportion of thermal to hydro generation (see Changes in Use of Storage, under Hydroelectric Resources) and greater irrigation depletions.

Hourly Flow Fluctuation

Three main factors affect the hourly discharge fluctuation at a run-of-river plant at any given site: the reservoir inflow, the plant hydraulic capacity, and the magnitude and shape of the system power load. Other things being equal, the smaller the average reservoir inflow, the larger the hourly fluctuation in discharge. When flows are low, the ponds of the run-of-river plants will be drafted heavily to meet daily loads; and hence, they must be refilled during off-peak hours. This means that off-peak releases will be relatively low, in some cases, limited to the minimum flows required for nonpower purposes. During the course of the day, the flows must be increased to meet the system load, reaching peaks in mid-morning and late afternoon. As shown by figure 22, with upstream storage it is possible to more efficiently distribute the annual runoff, thus eliminating the low average flows which would cause the greatest hourly fluctuation. Figure 24 shows how seasonal storage will increase the flows in January, the month having lowest natural flows, highest loads, and hence, the greatest hourly flow fluctuations. With higher flows, it will be possible to increase the minimum off-peak flows and to increase the number of hours the plants can operate at or near capacity.

Plant hydraulic capacity (or plant capability when expressed in terms of megawatts) also has a significant effect on the fluctuation of releases. Some of the older plants were initially constructed as base load plants, and the ratio of average usable energy to plant capability (capacity factor) of these plants is quite high. At plants of this type, the fluctuation in hourly releases is relatively low. Since hydro generation will increasingly be used for meeting peak loads instead of the base load, the newer plants have been designed with higher plant capabilities. Moreover, additions are planned to increase the capabilities of most of the existing plants (table 34). With the resulting lower capacity factors, these plants will create greater fluctuations in discharges. Table 46 shows the capacity factors of the Columbia River plants under 1980 and 2010 loads and resources. Large differences in the hydraulic capacities of adjacent projects will also foster large pool fluctuations.

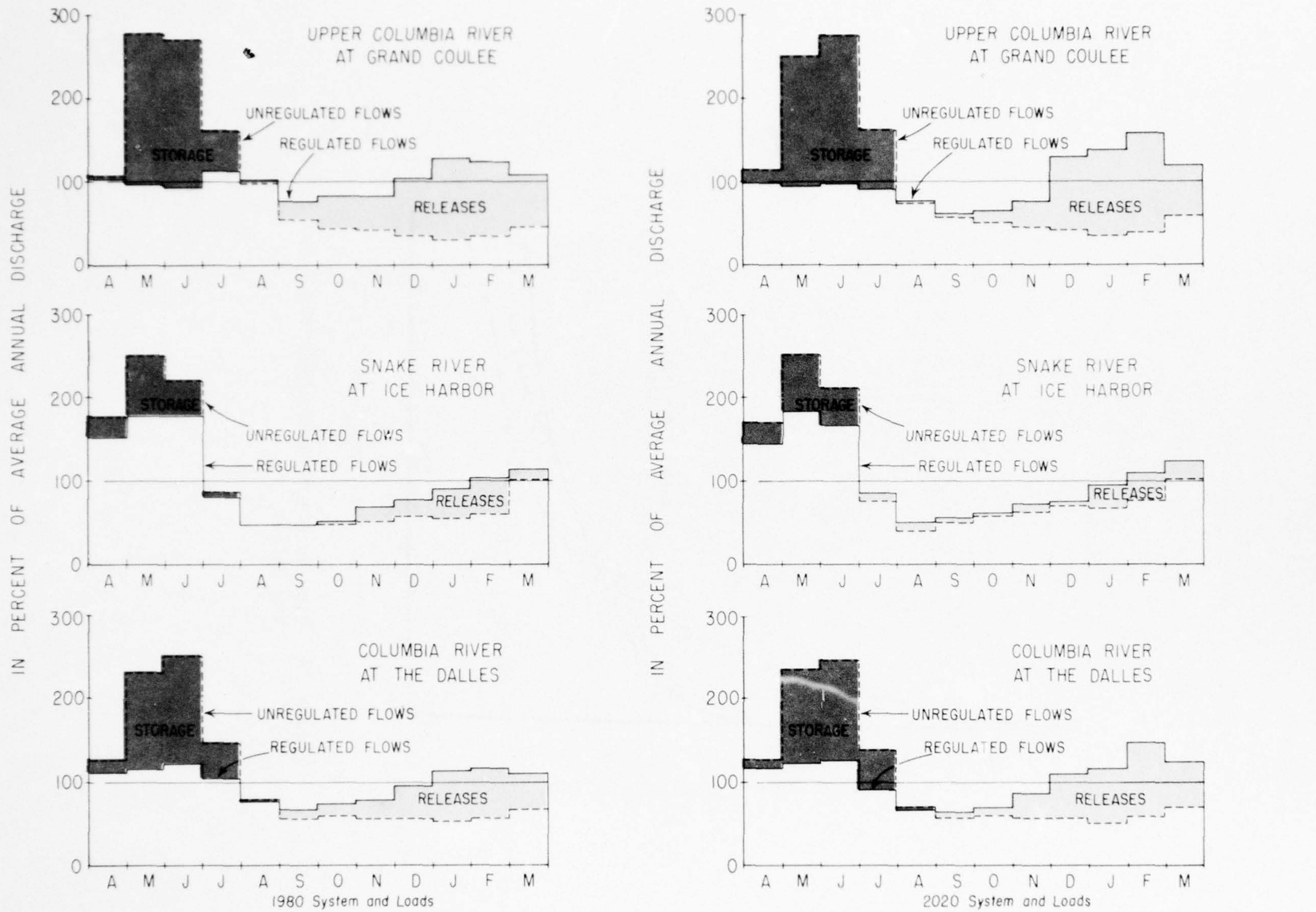


FIGURE 22. The Effect of Regulation on Mainstem Columbia and Lower Snake River Flows

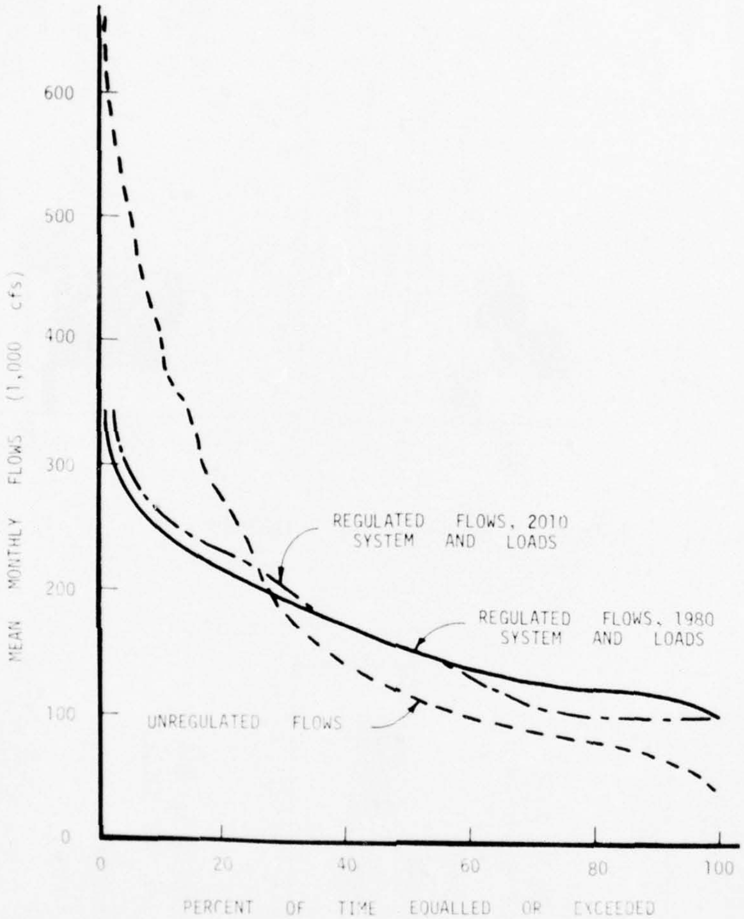


Figure 23. Flow Duration of Mean Monthly Flows at The Dalles

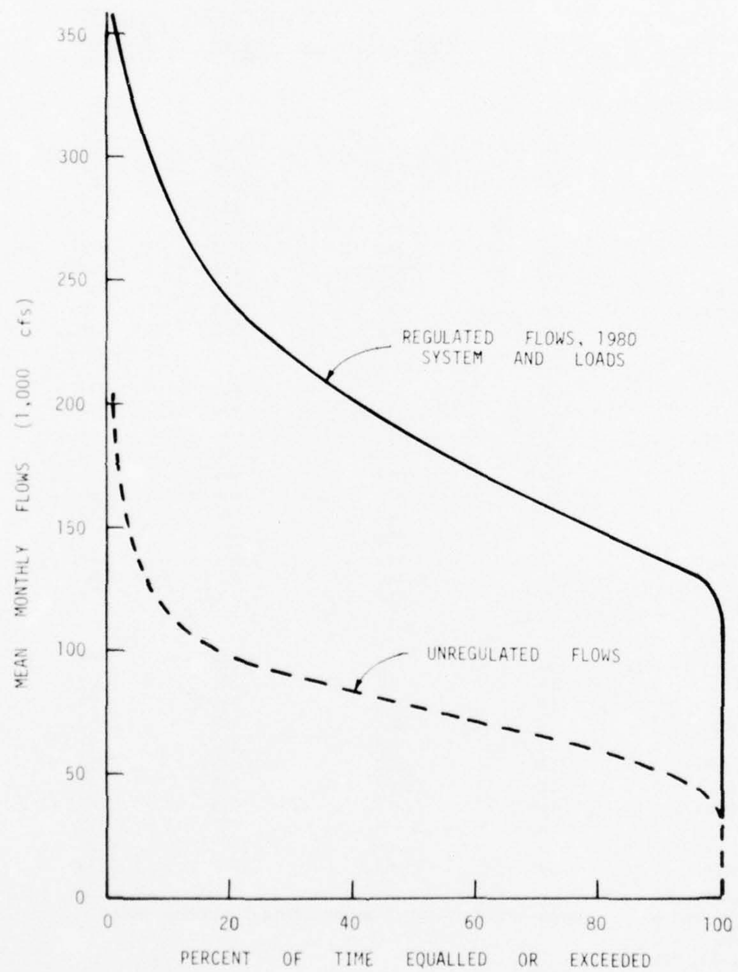


Figure 24. Flow Duration Curve of Mean January Flows at The Dalles

Table 46 - Annual Capacity Factors for Mainstem Columbia Projects

Project	Units	Plant Capability (MW)	Average Annual Energy (MW)	Capacity Factor (Percent)
Initial Conditions				
Rock Island	4	60	55	92
Bonneville	10	574	520	90
John Day	8 1/	1,242	1,014	82
Chief Joseph	16	1,280	1,017	80
McNary	14	1,127	840	74
Grand Coulee	18	2,292	1,643	72
The Dalles	14	1,283	913	71
Wells	7	618	414	67
Rocky Reach	7	815	529	65
Priest Rapids	10	912	545	60
Wanapum	10	983	567	58
1980 Conditions				
Rock Island	10	169	161	95
McNary	14	1,127	840	74
Priest Rapids	10	912	633	69
Wanapum	10	983	665	68
Bonneville	16	1,054	691	66
Wells	10	820	500	61
Rocky Reach	11	1,312	755	58
The Dalles	22	1,894	1,084	57
Grand Coulee	22	4,595	2,455	53
John Day	16	2,480	1,292	52
Chief Joseph	27	2,482	1,270	51
2020 Conditions				
Rock Island	10	169	148	88
Bonneville	16	1,054	701	67
Wells	10	820	481	59
Rocky Reach	11	1,312	694	53
McNary	20	1,610	817	51
Chief Joseph	27	2,482	1,245	50
The Dalles	22	1,894	915	48
Priest Rapids	16	1,362	608	45
Wanapum	16	1,449	620	43
John Day	20	3,105	1,197	39
Grand Coulee	30	9,240	2,299	25

1/ Initial installation contemplated at the time powerplant studies were completed.

Source: (6, 15, 36, 43)

The shape and magnitude of the regional load also has a major effect on hourly fluctuation of flows and has a direct influence on the seasonal regulation of streamflow and the determination of plant capacities as well. On an hourly basis, the shape of the daily load establishes the pattern of releases for power generation--the nighttime minimums and daily peaks discussed above. On weekends these peaks are generally lower and the hourly fluctuations are less than experienced during the week. Furthermore, weather and other factors cause variations in load over the course of the year. This seasonal variation in load, together with the seasonal variation in streamflow, has an effect on the operation of the hydroplants, with hourly fluctuations generally being greatest in mid-winter, and lowest in late spring and early summer.

As hydro generation shifts toward a predominantly peaking operation, additional capacity will be installed at most of the mainstem hydroplants, and with this increased capacity will come greater hourly fluctuations. Where projects are constructed in a continuous sequence, as on most of the Columbia and the Lower Snake, the hourly fluctuations which show up immediately downstream from each project will be rapidly attenuated in the downstream reservoir. Only where gaps are left in the "chain" of projects (as at Ben Franklin) and at the ends of the chain will the river stage be affected for a significant distance or will pools be required to fluctuate greatly.

Figures 25 through 28 illustrate the way in which hydro project forebay elevations, discharges, and tailwater elevations fluctuate during the course of typical weekly regulations. Regulations are shown for Chief Joseph, Ice Harbor, John Day, and Bonneville under two typical streamflow conditions: an average September streamflow (118,160 cubic feet per second at Bonneville) and a typical low-flow December (159,740 cubic feet per second). These streamflows reflect seasonal regulation similar to that shown on figure 22. It should be pointed out that the hourly pondage studies shown on figures 25 through 28 were produced using a computerized simulation program still in the development stage, and for this reason, they should be viewed with some reservations. However, they do serve to illustrate quite graphically the type of hourly fluctuations which could be expected.(35)

Table 47 summarizes the range of flows which would be experienced under normal plant operation. Fully acceptable minimum hourly flows have not yet been established for most of the mainstem Columbia plants. However, the Corps of Engineers, under its recently authorized Columbia River and Tributaries Study, is attempting to determine more accurately the plant operating criteria and constraints which would best serve the combined interests of power, water quality, fish and wildlife, recreation, flood control, and navigation. The criteria developed will apply primarily to

Table 47 - Hydraulic Capacities and Minimum Hourly Releases for Mainstem Columbia Projects

Project	Mean Annual Streamflow 1/ (cfs)	Initial Installation Units	Initial Installation Hydraulic Capacity (cfs)	1980 Conditions Units	1980 Conditions Hydraulic Capacity (cfs)	2020 Conditions Units	2020 Conditions Hydraulic Capacity (cfs)	Minimum Hourly Releases (cfs)	
Grand Coulee	100,535	18	92,000	24	270,000	30	388,000	No restrictions 2/	
Chief Joseph	100,700	16	109,000	27	208,000	27	208,000	" "	
Wells	104,900	10	230,000	10	230,000	10	230,000	" "	
Rocky Reach	107,400	7	121,000	11	210,000	11	210,000	" "	
Rock Island	110,400	10	80,000	10	80,000	10	80,000	" "	
Wanapum	110,500	10	178,000	10	178,000	16	289,000	7,500 cfs 2/	
Priest Rapids	110,754	10	187,000	10	187,000	16	294,000	36,000 cfs	
								Dec-Feb 3/	Mar-Nov 4/
McNary	164,000	14	227,000	14	227,000	20	340,000	36,000	54,000
John Day	166,000	16	345,000	16	345,000	20	450,000	38,000	50,000
The Dalles	171,332	14	211,000	22	357,000	22	357,000	39,000	57,000
Bonneville	177,400	10	135,000	16	252,000	16	252,000	58,000 5/	

1/ 1928-1958 flows adjusted for 1970 regulation and irrigation depletions (values for Chief Joseph, Wells, Rocky Reach, Rock Island, McNary, and John Day interpolated).

2/ Outflow must be sufficient to maintain hourly release of 36,000 cfs at Priest Rapids.

3/ For transmission system stability, at McNary--4 units @ minimum turbine output, at John Day--3 units @ minimum, at The Dalles--4 main units plus 2 fish turbines @ minimum.

4/ At McNary--6 units @ best turbine efficiency, at John Day--4 units @ best efficiency, at The Dalles--6 main units plus 2 fish turbines @ best efficiency (these minimum release values are tentative).

5/ For navigation (tentative).

Source: Streamflows: (21); Hydraulic Capacities (15,44).

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COLUMBIA-NORTH PACIFIC REGION COMPREHENSIVE FRAMEWORK STUDY OF --ETC(U)
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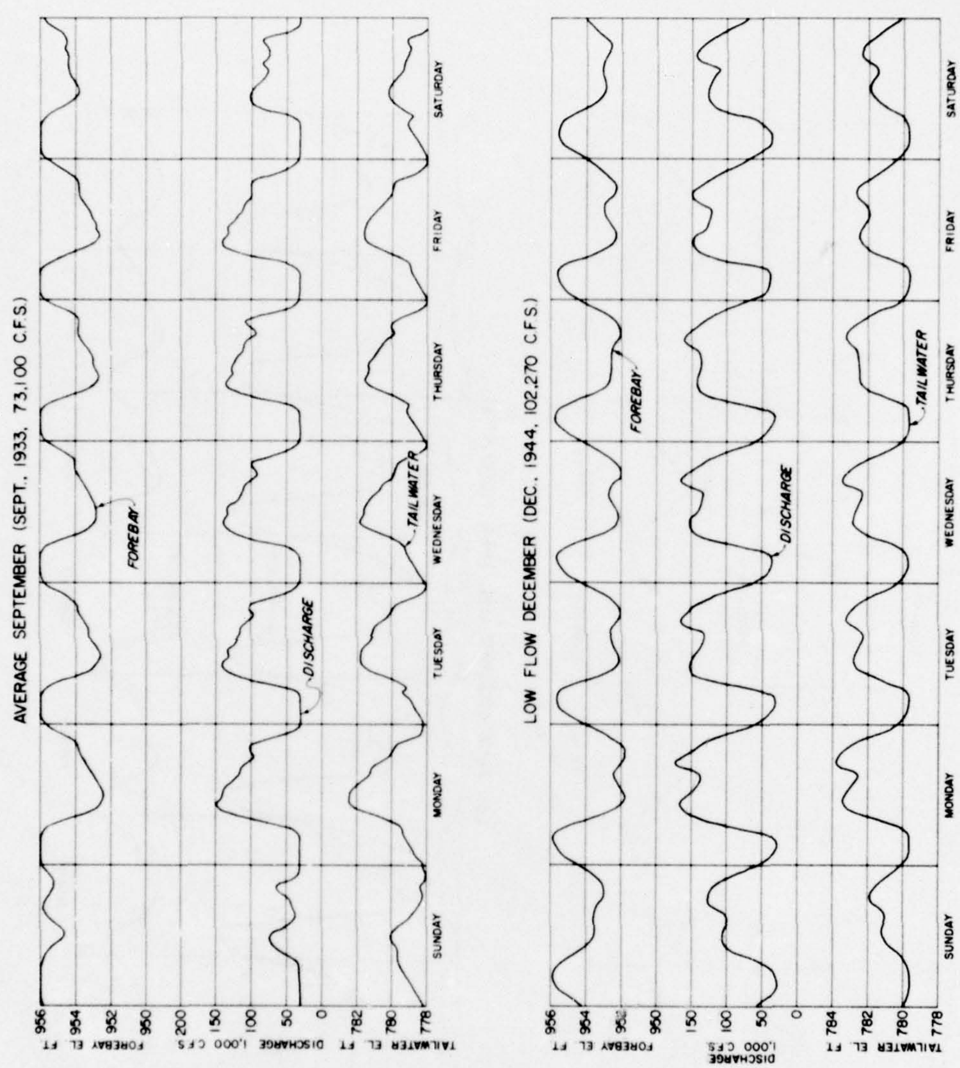


FIGURE 25. Weekly Fluctuations at Chief Joseph Dam, 1990 Conditions (27 Units).

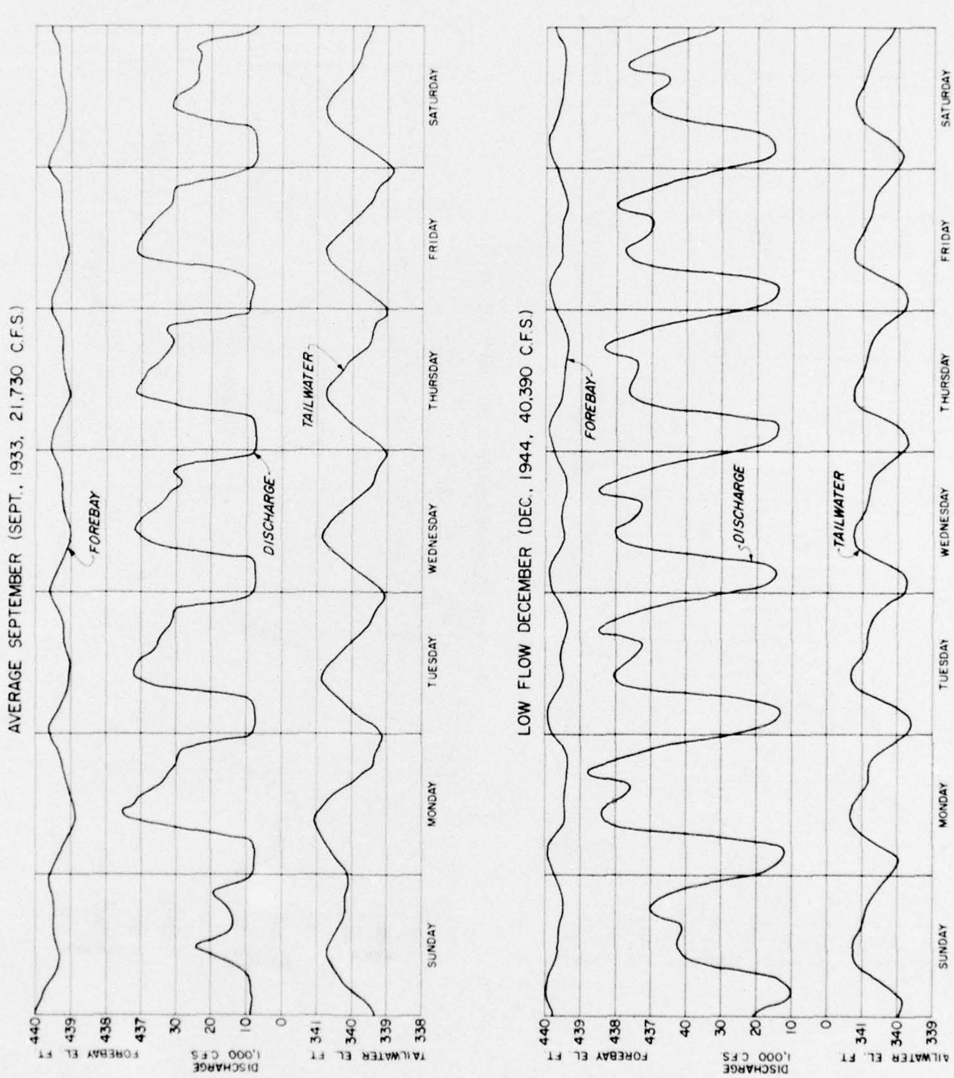


FIGURE 26. Weekly Fluctuations at Ice Harbor Dam, 1990 Conditions (6 Units).

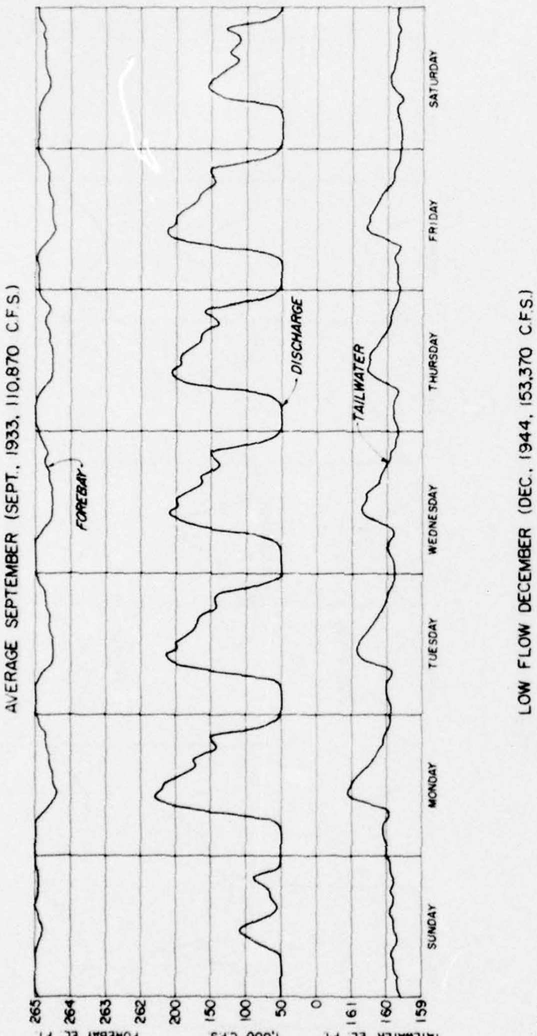


FIGURE 27. Weekly Fluctuations at John Day Dam, 1990 Conditions (16 Units).

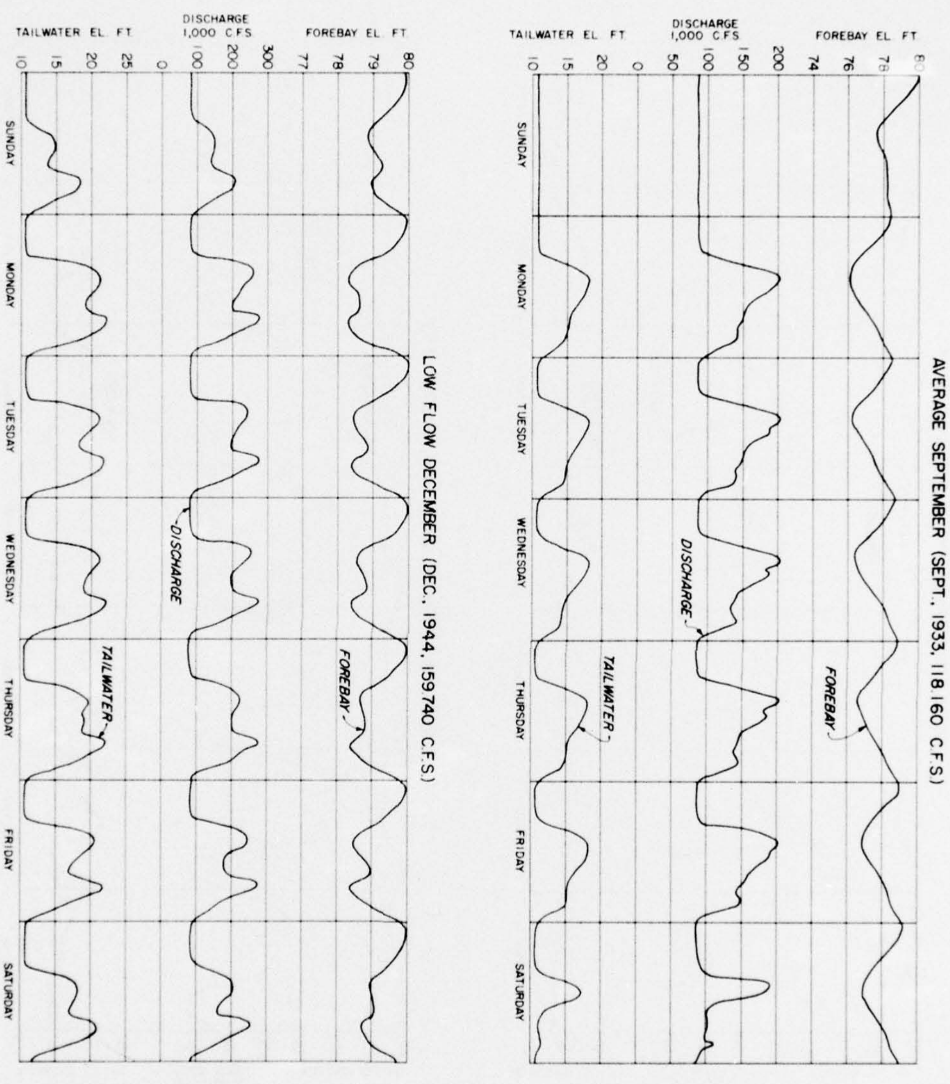


FIGURE 28. Weekly Fluctuations at Bonneville Dam, 1990 Conditions (Existing powerhouse plus 6-80 mw units. Minimum downstream release 85,000 cfs).

Corps projects, but it is hoped that the data will prove useful in assisting other project operators develop more effective reservoir regulation procedures. Some of the parameters involved in the study are pool fluctuations, minimum releases, and maximum rates of tailwater fluctuation. Consideration will be given to the effect of regulation on all activities on or adjacent to the reservoirs and the open reaches below the reservoirs. Input will be solicited from all interested agencies and organizations to insure that all aspects and effects of reservoir regulation will be given adequate consideration, and field tests will be conducted to verify the criteria developed through the study.

During periods of sustained high river flows, the plant hydraulic capacities may occasionally be exceeded. Under 1980 conditions, for example, it is estimated that on the average between 3 and 8 percent of the available energy will be spilled annually at the mainstem Columbia plants (except for Rock Island, which will spill nearly 30 percent). By 2020, when full plant capabilities have been attained and additional upstream storage is available for regulation, spilled energy will be less than 1 percent except for 5 percent at Bonneville and 35 percent at Rock Island.

Regulated Tributary Flows

In addition to the mainstem projects previously discussed, major hydroelectric developments are located or are under construction in the following subbasins (see figure 5):

Columbia River Tributaries

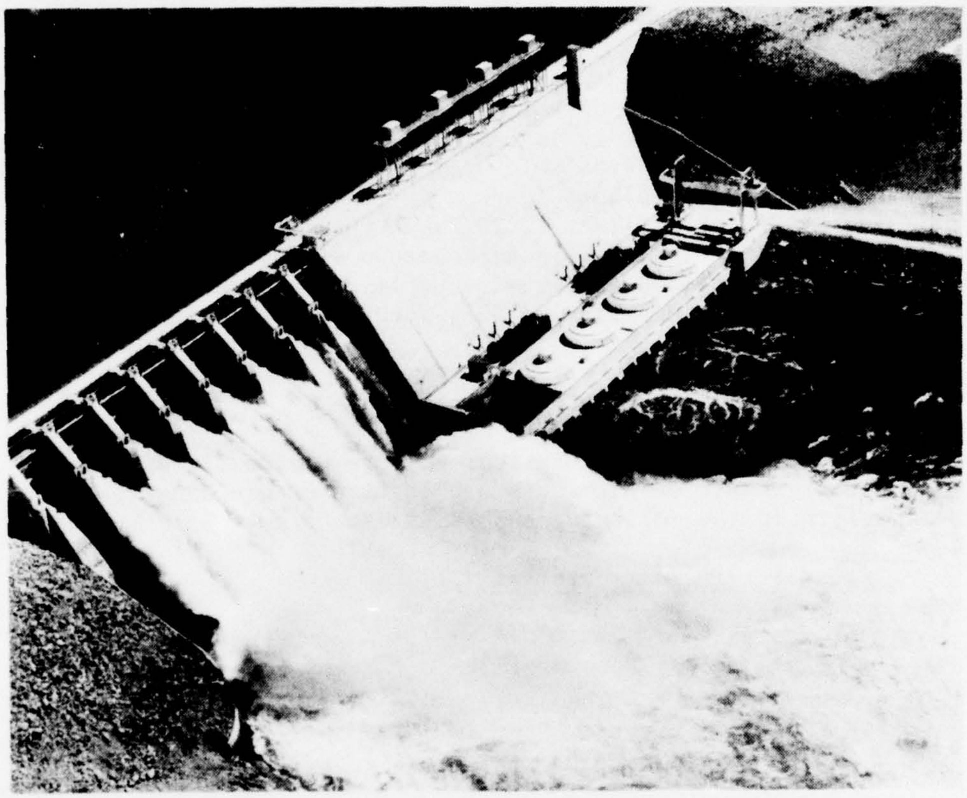
- Kootenai
- Clark Fork - Pend Oreille
- Spokane
- Chelan
- Snake
- Deschutes
- Willamette
- Lewis
- Cowlitz

Coastal Streams

- Skagit - Baker
- Nisqually
- Skokomish
- North Umpqua
- Rogue

A number of smaller, independent projects are located on other streams.

The projects on the streams listed above generally fall into four categories: (1) the Columbia River Basin power and flood control system projects, (2) independent systems of power projects, (3) independent power projects, and (4) independent flood control and irrigation system projects. Certain general comments can be made about the operation of projects in each of these categories. Projects in the last three categories were classified as Independent Resources in the system regulation studies discussed under Staging of Electric Power Development.



Noxon Rapids Dam on the Clark Fork River in Montana, an element of the coordinated Columbia River System (The Washington Water Power Co.).

Coordinated Columbia River System Projects

Included in this category are tributary projects which are hydraulically integrated with the mainstem Columbia projects for power and flood control purposes. This includes projects on the Kootenai, Flathead, Clark Fork - Pend Oreille, Spokane, Chelan, Middle Snake, Clearwater, Lower Snake, and Deschutes Rivers (table 48). The system includes both storage projects which are regulated seasonally in the interests of power and flood control,

and run-of-river power projects. These projects, together with the mainstem projects listed in table 47 make up the Coordinated Columbia River System. This system meets over 80 percent of the present load requirements of the region.

Monthly flow variation will be generally, as described for the mainstem Columbia--storage of surplus streamflow in late spring and early summer and releases from storage during late fall, winter, and early spring (figure 22). Hourly fluctuations from the run-of river plants are also generally similar to those described for the mainstem Columbia projects.

Hourly fluctuations at the storage projects vary seasonally. During periods of draft, the powerplants may operate for extended periods at full capacity, while during filling or holding periods, releases for power may be limited to occasional short periods of peaking, at which times fluctuations would be substantial. During off-peak periods, minimum releases are usually maintained for nonpower purposes.

In the future, as more storage becomes available, the monthly fluctuations will decrease (refer to discussion of mainstem Columbia monthly fluctuations). On the other hand, as thermal generation assumes an increasingly larger share of the base load, these projects will also be called on to operate more and more as peaking installations, and the downstream hourly flow fluctuations will become greater. Provision has been made at many of these plants for additional units to meet these peaking demands (table 33). At some projects it will be necessary to provide reregulating facilities to permit full development of the peaking potential while maintaining downstream fluctuations within reasonable limits.

Independent Systems of Power Projects

There are in the region a number of hydraulically independent systems of power projects, each located on a single stream and generally under the control of a single utility. These systems consist of a seasonal storage reservoir and one or more generating plants located downstream. An example would be Seattle City Light's Skagit River system, consisting of a storage reservoir and generating plant at Ross and generating plants at Diablo and Gorge. Other similar systems are located on the Clackamas, Lewis, Cowlitz, Skokomish, Nisqually, Baker, and North Umpqua Rivers (figure 5 and table 49). In addition, Washington Water Power's system of projects on the Spokane River and Idaho Power's Brownlee-Oxbow-Hells Canyon system (table 48) are in many ways similar, but are hydraulically integrated in the coordinated Columbia River system.

Table 48 - Tributary Projects Operationally Integrated With Mainstem Columbia Projects

Project	Owner	First Year of Operation	PRESENT DEVELOPMENT Max. Plant Capability MW	PRESENT DEVELOPMENT Ave. Annual Energy1/ Average MW	PRESENT DEVELOPMENT Annual Plant Factor Percent	ULTIMATE DEVELOPMENT Max. Plant Capability MW	ULTIMATE DEVELOPMENT Ave. Annual Energy2/ Average MW	ULTIMATE DEVELOPMENT Annual Plant Factor Percent	Pondage or Seasonal Storage Acre-Feet
Kootenai River									
Libby	Corps of Engineers	3/	483.0	210	43	966.0	180	19	4,905,0004/
Libby Reregulator	Corps of Engineers	6/	-	-	-	50.0	31	62	30,000
Duncan5/	British Columbia Hydro	1967	0	-	-	0	-	-	1,402,000
Corra Linn5/	COMINCO, Ltd.	1932	48.0	48	100	48.0	46	96	817,0004/
Upper Bonnington5/	COMINCO, Ltd.	1907	60.0	59	98	60.0	57	95	Pondage
Lower Bonnington5/	West Kootenay Power & Light Co.	1899	45.0	45	100	45.0	44	98	Pondage
South Slocan5/	COMINCO, Ltd.	1928	54.0	54	100	54.0	53	98	Pondage
Brilliant5/	COMINCO, Ltd.	1944	120.0	115	96	120.0	107	89	Pondage
Clark Fork-Pend Oreille & Tributaries									
Hungry Horse	Bureau of Reclamation	1952	328.0	103	31	328.0	102	31	3,161,0004/
Kerr	Montana Power Co.	1938	185.0	118	64	185.0	108	58	1,219,0004/
Thompson Falls	Montana Power Co.	1915	40.0	137	92	40.0	36	90	15,000
Cabinet Gorge	Washington Water Power Co.	1952	230.0	122	53	230.0	118	51	42,780
Noxon Rapids	Washington Water Power Co.	1959	430.0	186	43	538.0	183	34	230,6804/
Albeni Falls	Corps of Engineers	1955	49.0	19	39	49.0	26	53	1,155,0004/
Box Canyon	Pend Oreille County PUD	1955	77.2	54	70	77.2	50	65	10,000
Boundary	Seattle City Light	1967	650.0	411	63	943.9	440	47	43,000
Waneta5/	COMINCO, Ltd.	1954	362.0	302	83	362.0	286	79	3,370
Spokane River									
Post Falls	Washington Water Power Co.	1906	13.2	10	76	13.2	10	76	223,1004/
Upper Falls	Washington Water Power Co.	1922	10.2	9	88	10.2	8	78	800
Monroe Street	Washington Water Power Co.	1903	7.2	6	83	7.2	6	83	0
Nine Mile	Washington Water Power Co.	1908	18.0	14	78	18.0	13	72	4,000
Long Lake	Washington Water Power Co.	1915	72.5	53	73	72.5	51	70	105,080
Little Falls	Washington Water Power Co.	1910	34.1	25	73	34.1	24	70	2,220
Chelan River									
Chelan	Chelan County PUD	1927	53.0	43	81	53.0	39	74	676,1004/
Snake River & Tributaries									
Brownlee	Idaho Power Company	1958	450.0	269	60	675.0	253	37	980,2504/
Oxbow	Idaho Power Company	1961	220.0	114	52	275.0	108	39	5,000
Hells Canyon	Idaho Power Company	1967	450.0	232	52	450.0	211	47	11,800
Dworshak	Corps of Engineers	3/	460.0	208	45	1219.0	219	18	2,000,0004/
Lower Granite	Corps of Engineers	3/	465.8	277	59	931.5	310	33	43,600
Little Goose	Corps of Engineers	1970	465.8	275	59	931.5	307	33	49,000
Lower Monumental	Corps of Engineers	1969	465.8	283	61	931.5	313	34	20,000
Ice Harbor	Corps of Engineers	1961	693.3	306	44	693.3	292	42	24,860
Deschutes River									
Round Butte	Portland General Electric Co.	1964	330.0	106	32	330.0	108	33	274,2254/
Pelton	Portland General Electric Co.	1957	124.0	47	38	124.0	47	38	3,800

1/ Based on 30 years of flow (1928-58), and 1975-76 loads and resources.
2/ Based on 30 years of flow (1928-58), and 2010 loads and resources.
3/ Under construction 1970.
4/ Seasonal storage.
5/ Canadian project.
6/ Construction not yet scheduled.

Sources: (5, 6, 9, 11, 12, 15, 16, 45, 47)

Table 49 - Independent Power Systems, Columbia-North Pacific Region

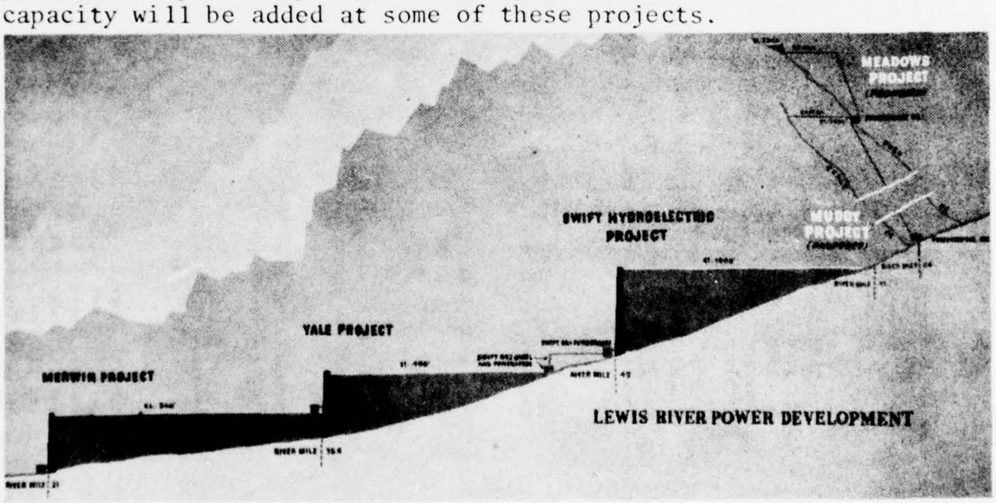
Project	Owner	First Year of Operation	Max. Plant Capability MW	Ave. Annual Energy 1/ Average MW	Annual Plant Factor Percent	Pondage or Seasonal Storage Acre-Feet
Clackamas River						
Timothy Meadows	Portland General Electric Co.	1956	0.0	-	-	61,740 2/
Oak Grove	Portland General Electric Co.	1924	49.0	27.0	55	546
North Fork	Portland General Electric Co.	1958	54.0	25.7	48	5,994
Faraday	Portland General Electric Co.	1907	44.0	23.0	52	550
River Mill	Portland General Electric Co.	1911	23.0	12.7	55	770
Lewis River						
Swift No. 1	Pacific Power & Light Co.	1958	268.0	72.5	27	446,995 2/
Swift No. 2	Cowlitz County PUD No. 1	1958	77.0	25.8	34	0
Yale	Pacific Power & Light Co.	1953	134.0	63.2	47	189,200 2/
Merwin	Pacific Power & Light Co.	1931	150.0	62.6	42	181,880 2/
Cowlitz River						
Mossyrock	Tacoma City Light	1968	384.0	105.5	27	1,297,000 2/
Mayfield	Tacoma City Light	1963	133.0	71.2	54	21,378
Skagit River						
Ross	Seattle City Light	1940	446.0	86.6	20	1,052,753 2/
Diablo	Seattle City Light	1936	159.0	91.5	58	24,700
Gorge	Seattle City Light	1924	175.0	104.9	60	6,545
Baker River						
Upper Baker	Puget Sound Power & Light Co.	1959	103.0	40.5	39	220,634 2/
Lower Baker	Puget Sound Power & Light Co.	1925	71.4	43.4	61	142,365 2/
Nisqually River						
Alder	Tacoma City Light	1945	52.0	24.8	48	179,800 2/
La Grande	Tacoma City Light	1912	65.0	39.5	61	1,000
Skokomish River						
Cushman No. 1	Tacoma City Light	1926	47.0	11.5	24	107,000 2/
Cushman No. 2	Tacoma City Light	1930	88.0	24.0	27	2,500
North Umpqua River						
Lemolo No. 1	Pacific Power & Light Co.	1955	30.0	23.0	77	12,630 2/
Lemolo No. 2	Pacific Power & Light Co.	1956	35.1	23.8	68	235
Clearwater No. 1	Pacific Power & Light Co.	1953	18.7	6.9	37	154
Clearwater No. 2	Pacific Power & Light Co.	1953	32.0	10.8	34	96
Toketee	Pacific Power & Light Co.	1950	44.5	27.9	63	1,420
Fish Creek	Pacific Power & Light Co.	1952	12.4	8.6	70	78
Slide Creek	Pacific Power & Light Co.	1951	19.0	12.2	64	0
Soda Springs	Pacific Power & Light Co.	1952	12.0	7.1	59	710

1/ Based on 30 years of flow (1928-58), present loads, and present resources.
2/ Seasonal storage.

Sources: (6, 9, 12, 15, 16, 20, 23)

Typical operation of these independent systems is as follows: Water is stored in the upstream storage reservoirs during the season of heavy runoff and is released as needed to meet system loads. While the seasonal regulation pattern varies from system to system, depending on the natural streamflow regime, generally speaking, it can be said that the operation of the systems tend to reduce seasonal fluctuations by reducing the annual peaks and increasing dry season flows. The hourly fluctuations at these plants are dependent on the same factors as are the mainstem Columbia plants. At some of the run-of-river plants, such as the Spokane River plants, both hydraulic capacity and pondage are quite limited, and fluctuations are comparatively small. At other plants, where sufficient pondage is available, it has been possible to install larger capacities and operate as peaking plants, and as a result, hourly fluctuations are relatively high. However, to minimize fluctuations downstream, the farthest downstream plant usually serves as a reregulator to damp out the large hourly fluctuations experienced at the upper plants. In the case of the Deschutes River system, a special reregulating dam was constructed below the last downstream project.

In the future, these projects will continue to operate more and more as peaking plants within the limitations of available pondage and plant capacity. It is probable that additional capacity will be added at some of these projects.



The Lewis River hydroelectric system, a typical independent system of power projects (Pacific Power & Light Co.).

Independent Power Projects

Besides those projects included in the systems described above, there are a number of small single-purpose hydro projects, which are for all practical purposes hydraulically independent of the other hydro projects in the region (table 50). These projects

Table 50 - Independent Power Projects, Columbia-North Pacific Region

Project	Owner	First Year of Operation	Max. Plant Capability MW	Ave. Annual Energy 1/ Average MW	Annual Plant Factor Percent	Pondage or Seasonal Storage Acre-Feet
Kootenai River & Tributaries						
(Upper Moyie	City of Bonners Ferry	1921	2.2	1.1	50	Pondage
(Lower Moyie	City of Bonners Ferry	1941	0.4	0.2	50	0
Lake Creek No. 1	Montana Light & Power Co.	1916	1.2	1.0	80	30
Lake Creek No. 2	Montana Light & Power Co.	1949	4.2	2.2	52	0
Pend Oreille-Clark Fork & Tributaries						
Flint Creek	Montana Power Co.	1901	1.1	0.9	82	23,300 3/
Milltown	Montana Power Co.	1906	3.4	2.3	68	300
Big Fork	Pacific Power & Light Co.	1901	4.6	3.9	85	109
Colville River						
Meyers Falls	Washington Water Power Co.	1915	1.4	1.0	71	Pondage
Snake River & Tributaries						
Strawberry Creek	Lower Valley Power & Light Co.	1951	1.5	0.9	60	6
Ashton	Utah Power & Light Co.	1917	6.0	3.8	63	1,800
Teton River (Felt)	Fall River Cooperative	1921	2.1	1.0	48	Pondage
Idaho Falls, Upper	City of Idaho Falls	1930	2.4	1.8	75	0
Idaho Falls, Lower	City of Idaho Falls	1904	3.1	2.7	87	0
Idaho Falls	City of Idaho Falls	1913	2.0	1.6	80	0
American Falls	Idaho Power Co.	1902	27.3	16.8	62	0
Twin Falls	Idaho Power Co.	1935	9.8	8.0	85	750
Shoshone Falls	Idaho Power Co.	1907	12.5	10.6	85	560
Clear Lake	Idaho Power Co.	1937	2.2	2.1	95	0
Thousand Springs	Idaho Power Co.	1912	7.6	7.5	98	0
Upper Salmon A	Idaho Power Co.	1937	19.5	19.1	98	0
Upper Salmon B	Idaho Power Co.	1947	17.5	16.7	95	1,200
Lower Salmon	Idaho Power Co.	1949	68.6	31.5	46	3,600
Upper Malad	Idaho Power Co.	1948	7.6	7.5	98	0
Lower Malad	Idaho Power Co.	1948	13.9	12.0	86	0
Bliss	Idaho Power Co.	1949	79.0	46.5	59	1,200
C. J. Strike	Idaho Power Co.	1952	89.0	59.9	67	35,000 3/
Swan Falls	Idaho Power Co.	1910	12.0	11.5	96	6,840
Lewiston	Washington Water & Power Co.	1927	10.4	8.7	84	2,340
Deschutes River						
Bend	Pacif'c Power & Light Co.	1913	1.0	.8	80	0
Cline Falls	Pacific Power & Light Co.	1913	1.0	.6	60	0
Hood River						
Powerdale	Pacific Power & Light Co.	1923	6.5	5.3	82	0
White Salmon River						
Condit	Pacific Power & Light Co.	1913	15.0	10.6	71	1,081
Sandy River						
Bull Run	Portland General Electric Co.	1912	22.0	17.4	79	970
amette River & Tributaries						
armen	City of Eugene	1963	101.6	25.7	25	12,000 3/
rail Bridge	City of Eugene	1963	11.4	5.5	48	2,113
aterville	City of Eugene	1911	9.5	8.4	88	345
eaburg	City of Eugene	1929	14.8	13.4	90	0
ullivan	Portland General Electric Co.	1886	15.0	9.9	66	0
itz River & Tributaries						
ackwood Lake	Washington Public Power	1964	31.5	10.3	33	3,500 3/
t Sound Tributaries						
ooksack	Puget Sound Power & Light Co.	1906	1.7	0.3	18	Pondage
ewhalem	Seattle City Light	1921	2.0	1.4	70	1
noqualmie Falls	Puget Sound Power & Light Co.	1898	44.0	32.9	75	390
hite River	Puget Sound Power & Light Co.	1912	63.8	36.0	56	46,655 3/
lectron	Puget Sound Power & Light Co.	1904	26.4	20.3	77	54
edar Falls	Seattle City Light	1904	30.0	11.1	37	60,000 2/
elm	City of Centralia	1930	10.1	9.7	96	0
e River & Tributaries						
rospect No. 1	Pacific Power & Light Co.	1912	4.6	2.8	61	20
rospect No. 2	Pacific Power & Light Co.	1928	36.8	31.4	85	100
rospect No. 3	Pacific Power & Light Co.	1932	7.8	5.5	70	0
rospect No. 4	Pacific Power & Light Co.	1944	1.3	0.9	69	20
agle Point	Pacific Power & Light Co.	1957	3.2	2.2	69	0
old Ray	Pacific Power & Light Co.	1905	1.3	1.2	92	0

n most cases bases on 30 years of flow (1928-58), present loads, and present resources.
torage primarily for municipal water supply.
easonal storage.

ces: (6, 9, 12, 15, 16, 20, 23, 32)

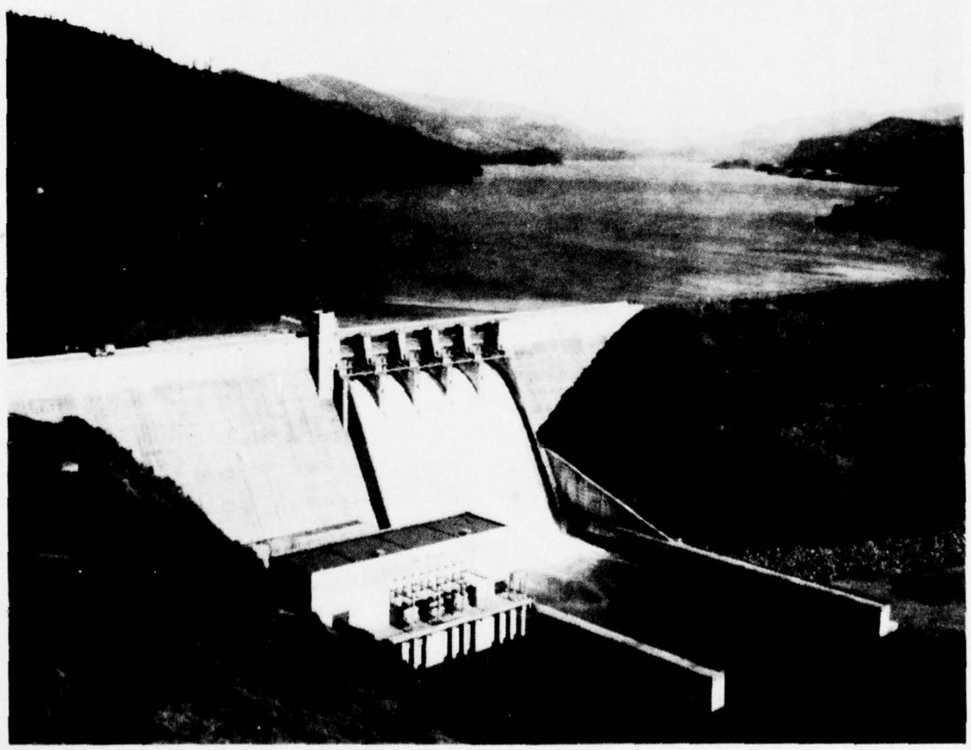
are usually run-of-river projects with limited pondage, depending mainly on natural streamflows for energy. Because of the lack of upstream storage and the limited pondage available, most of the plants were designed to operate at high capacity factors. For a large part of the year the flows are sufficient to permit generation at or near full capacity. During the low flow periods, the limited pondage is used to permit a certain amount of peaking, and as a result, some hourly flow fluctuation is experienced. A few of the independent power projects do have a substantial amount of pondage, which permits additional daily and weekly flexibility in power operations. Examples are the C. J. Strike project on the Upper Snake and the White River project in the Puget Sound Subregion. However, the amount of storage available at most of these projects is so small that they do not have any significant effect on seasonal flow variations. Most of the independent projects are comparatively old, and with a few exceptions (Lower Salmon and Bliss on the Upper Snake and White River in the Puget Sound Subregion), no provision has been made for installing additional capacity. Therefore, it is not anticipated that any significant change in operation will occur in the future, except at those few plants where additional capacity will be installed. However, some projects may be redeveloped, possibly as peaking plants.

C. J. Strike Dam, an independent hydroelectric project on the Snake River in Southern Idaho (Idaho Power Co.).

Independent Flood Control and Irrigation Systems and Projects

Power facilities have been installed at a number of multiple-purpose reservoirs constructed primarily for flood control and/or irrigation (table 51). As seasonal operation of these reservoirs is normally dependent on their primary function, the monthly flow fluctuations will not be significantly affected by power operations. However, within the constraints of the conservation and flood control operations, a certain amount of latitude is available within which hourly, daily, and even weekly power regulation can be accomplished.

The high heads available at some of these projects make them particularly attractive as peaking plants. At Detroit, Green Peter, and Lookout Point, flood control reservoirs in the Willamette Basin, reregulating reservoirs have been provided to permit peaking operations without causing excessive downstream fluctuations. Where reregulation is not provided, the size of the installation has been limited. In addition, stipulated minimum releases and maximum rates of change in release are maintained at all of the Willamette and Rogue River Basin flood control reservoirs.



Lookout Point Dam, a multipurpose project on the Willamette River, Oregon (Corps of Engineers).

Table 51 - Independent Flood Control & Irrigation Projects With Power Generation Facilities, Columbia-North Pacific Region

Project	Owner[1/]	Type of Project	First Yr. of Operation	Max. Plant Capability MW	Ave. Annual Energy[2/] Average MW	Annual Plant Factor Percent	Usable Storage 1000 A-F	Primary Non-Power Function
Yakima River & Tributaries								
Roza	USBR	Run-of-Canal	1958	11.2	9.2	82	0	Irrigation
Chandler	USBR	Run-of-Canal	1956	12.0	8.7	72	0	Irrigation
Wapato Drop #2	WID	Run-of-Canal	1942	2.4	0.7	29	0	Irrigation
Wapato Drop #3	WID	Run-of-Canal	1932	1.2	0.3	25	0	Irrigation
Naches	PP&L	Run-of-Canal	1909	5.0	3.8	76	0	Irrigation
Naches Drop	PP&L	Run-of-Canal	1914	1.4	1.1	78	0	Irrigation
Snake River & Tributaries								
Palisades	USBR	Storage	1957	136.0	74.3	55	1,202.0	Irrigation[4/]
Teton [3/]	USBR	Storage	3/	22.0	8.6	39	200.0	Irrigation[4/]
Minidoka	USBR	Storage	1909	15.6	10.7	68	95.2	Irrigarion
Anderson Ranch	USBR	Storage	1950	34.5	18.4	53	423.0	Irrigation[4/]
Boise Diversion	USBR	Run-of-River	1912	2.2	1.2	53	0	Irrigation
Black Canyon	USBR	Run-of-River	1925	10.2	9.1	90	Pondage	Irrigation
Willamette River & Tributaries								
Hills Creek	USCE	Storage	1962	34.5	18.5	54	243.6	Flood Control[5/]
Lookout Point	USCE	Storage	1954	138.0	36.7	26	336.5	Flood Control[5/]
Dexter	USCE	Reregulator	1955	17.2	9.5	55	Pondage	Flood Control
Cougar	USCE	Storage	1964	28.8	17.3	60	154.0	Flood Control[5/]
Green Peter	USCE	Storage	1968	92.0	27.1	29	333.0	Flood Control[5/]
Foster	USCE	Storage, Rereg.	1969	23.0	14.4	63	33.6	Flood Control[5/]
Detroit	USCE	Storage	1953	115.0	45.5	40	323.0	Flood Control[5/]
Big Cliff	USCE	Reregulator	1954	20.7	12.2	59	Pondage	Flood Control
Rogue River & Tributaries								
Lost Creek	USCE	Storage	3/	56.3	34.6	61	315.0	Flood Control[2/]
Green Springs	USBR	Run-of-Canal	1960	18.4	7.1	38	Pondage	Irrigation

1/ USBR, US Bureau of Reclamation; WID, Wapato Irrigation District; PP&L, Pacific Power & Light Company; USCE, US Corps of Engineers.
2/ Based on 30 years of flows (1928-58), present loads, and present resources.
3/ Under construction-1970.
4/ Also seasonal flood control.
5/ Also seasonal conservation storage for irrigation, etc.

Sources: (6, 9, 12, 15, 23)

At irrigation reservoirs, power generation is almost wholly dependent on irrigation release requirements during the irrigation season; and, in some cases, a large part of the generation thus obtained is used for irrigation pumping. As the irrigation release demand is fairly steady during most of the season, relatively little fluctuation is experienced. During the nonirrigation season, however, a certain amount of flexibility in power operation is possible, and hourly fluctuations of the type described for the mainstem Columbia projects will be experienced. However, the flow available for power generation during the nonirrigation season is limited by the need to store water for the subsequent irrigation season.

Changes in the monthly and hourly fluctuation patterns may occur at these projects in the future, but the changes will be related to the nonpower functions. At a few projects, however, it is possible that additional capacity may be added to increase their peaking capability. Examples are Cougar in the Willamette and Palisades in the Upper Snake Subregions. Reregulation would be required at these plants to permit full utilization of their peaking potential.

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G L O S S A R Y

APPLIANCE SATURATION - Ratio of the number of homes using a specific appliance to the total number of homes.

AVERAGE MEGAWATT - A unit of average energy output over a specified time period (total energy in megawatt-hours divided by the number of hours in the time period).

BASE LOAD - See Load, Base.

BLOWDOWN - Water drawn from boiler systems and cold water basins of cooling towers to prevent buildup of solids concentrations. Usually contains chemicals used for pH adjustment and slime control.

BRITISH THERMAL UNIT (Btu) - The standard unit for measurement of the amount of heat energy, such as the heat content of fuel. Equal to the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

CAPABILITY - The maximum load which a generator, turbine, power plant, transmission circuit, or power system can supply under specified conditions for a given time interval without exceeding approved limits of temperature and stress.

Maximum Plant Capability (Hydro) The maximum load which a hydroelectric plant can supply under optimum head and flow conditions without exceeding approved limits of temperature and stress. This may be less than the overload rating of the generators due to encroachment of tailwater on head at high discharges.

Peaking Capability - The maximum peak load that can be supplied by a generating unit, station, or system in a stated time period. For a hydro project the peaking capability would be equal to the maximum plant capability only under favorable pool and flow conditions, often the peaking capability may be less due to reservoir drawdown or tailwater encroachment.

Ultimate Plant Capability (Hydro) - The maximum plant capability of a hydroelectric plant when all contemplated generating units have been installed.

CAPACITY - The load for which a generator, transmission circuit, power plant, or system is rated. Capacity is also used synonymously with capability.

Dependable Capacity - The load-carrying ability of a station or system under adverse conditions for the time interval and period specified when related to the characteristics of the load to be supplied. For hydro projects the term refers to the capability in the most adverse month in the critical period--January 1932 in the case of the 1928-32 critical period.

Firm Capacity - Capacity which has assured availability to the customer on a demand basis. System firm capacity consists essentially of hydro system dependable capacity plus thermal plant installed capacity plus firm imports minus maintenance and forced outage reserves.

Hydraulic Capacity - The maximum flow which a hydroelectric plant can utilize for power generation.

Installed Capacity - Same as nameplate capacity unless otherwise specified.

Nameplate Capacity - The nominal rated capacity of a generating unit or other similar apparatus. The term gives an indication of the approximate generating capability of the unit, but in many cases the unit is capable of generating on a continuous basis substantially more than the nameplate capacity (see Overload Capacity, below).

Overload Capacity - The maximum load that a machine, apparatus, or device can carry for a specified period of time under specified conditions when operating beyond its nameplate rating but within the limits of the manufacturer's guarantee or, in the case of expiration of the guarantee, within safe limits as determined by the owner. For example, most of the generators installed in the region's newer hydroelectric plants have a continuous overload capacity of 115 percent of the nameplate capacity.

Peaking Capacity - Same as Peaking Capability.

Reserve Capacity - Extra generating capacity available to meet unanticipated demands for power or to generate power in the event of loss of generation resulting from scheduled or unscheduled outages of regularly used generating capacity.

CAPACITY FACTOR - The ratio of the average load on the generating plant for the period of time considered to the capacity rating of the plant. Unless otherwise identified, capacity factor is computed on an annual basis. In this Appendix, the capacity factor of a hydro plant is based on maximum plant capability and assumed load equal to the average annual energy.

CIRCULATING WATER - See Condenser cooling water. In a closed-cycle cooling system, this refers to the heated water from the condenser which is cooled, usually by evaporative means, and recycled through the condenser.

CONDENSER COOLING WATER - Water required to condense the steam after its discharge from a steam turbine.

CONVENTIONAL HYDROELECTRIC PLANT - A hydroelectric power plant which utilizes streamflow only once as it passes downstream, as opposed to a pumped-storage plant which recirculates all or a portion of the streamflow in the production of power.

COOLING WATER CONSUMPTION - The cooling water withdrawn from the source supplying a generating plant which is lost to the atmosphere. Caused primarily by evaporative cooling of the heated water coming from the condenser. The amount of consumption (loss) is dependent on the type of cooling employed--direct (once-through) cooling pond, or cooling tower. When not returned to the source of supply, blowdown is also included as a consumptive loss.

COOLING WATER LOAD - Waste heat energy dissipated by the cooling water.

COOLING WATER REQUIREMENT - The amount of water needed to pass through the condensing unit in order to condense the steam to water. This amount is dependent on the type of cooling employed and water temperature.

COORDINATED COLUMBIA RIVER SYSTEM - Contractually, the system of hydroelectric projects located on the Columbia River and major tributaries which are operated together on a coordinated basis under the terms of the Pacific Northwest Coordination Agreement. The term is sometimes used in a more general sense to include also those projects which are operated by utilities not participating in the Coordination Agreement.

COORDINATION AGREEMENT - See pages 31-34.

CRITICAL PERIOD - Period when the limitations of hydroelectric power supply due to water conditions are most critical with

respect to system energy requirements. For a discussion of the critical period as it applies to the regional hydroelectric system, refer to page 135.

CRITICAL WATER YEAR - A term sometimes used interchangeably with Critical Period when the critical period falls within one operating year. The term will lose all significance when the system moves into a multi-year critical period (see page 136).

DEMAND - The rate at which electric energy is delivered to or by a system at a given instant or averaged over any designated period of time, expressed in kilowatts or other suitable units.

DRAWDOWN - The distance that the water surface of a reservoir is lowered from a given elevation as the result of the withdrawal of water. In specific cases in this Appendix, drawdown may refer to the maximum drawdown for power operation, from normal full pool to minimum power pool. Sometimes drawdown is also expressed in terms of acre-feet of storage withdrawn.

ELECTRO-PROCESS INDUSTRY - An industry which requires very large amounts of electricity in manufacturing for heat or chemical processes (as distinguished from wheel-turning or mechanical applications). Examples are electric furnace steel, aluminum, and chlorine.

ENERGY - That which does or is capable of doing work. It is measured in terms of the work it is capable of doing; electric energy is commonly measured in kilowatt-hours or average megawatts.

Average Annual Energy - Average annual energy generated by a hydroelectric project or system over a specified period. In the Pacific Northwest the average output of most projects is based on the historical flows experienced during the period 1928-58, as modified by appropriate irrigation depletions.

Firm Energy - Electric energy which is considered to have assured availability to the customer to meet all or any agreed upon portion of his load requirements. Firm energy is based on certain specified probability considerations, which, in the Pacific Northwest, are related to the 1928-58 sequence of historical streamflows adopted for making system power regulations. System firm energy capability includes hydro system prime energy, thermal plant energy capabilities, and firm imports.

Prime Energy - Hydroelectric energy which is assumed to be available 100 percent of the time: specifically, the average energy generated during the critical period.

Secondary Energy - All hydroelectric energy other than prime energy: specifically, the difference between average annual energy and prime energy.

Usable Energy - All hydroelectric energy which can be used in meeting system firm and secondary loads. In the early years of this study, it is possible that there may not be a market for all of the secondary energy which could be generated in years of abundant water supply and some of the water may have to be diverted over project spillways and the energy wasted.

ENERGY CONTENT CURVE - A seasonal guide to the use of reservoir storage for at-site and downstream power generation. It is based on the following constraints: (1) During drawdown sufficient storage shall remain in the reservoir to insure meeting its share of the system firm energy requirements in the event of critical period water conditions, (2) Draft of storage for secondary energy production is permitted only to the extent that it will not jeopardize reservoir refill by the end of the coming July. Drafting below the assured refill level is permitted only if required to meet firm energy loads or if such draft is secured by a commitment to return energy equivalent to the drafted water if refill is not otherwise accomplished.

ENERGY DEMAND - See Demand.

FIRM - Assured.

FIRM LOAD CARRYING CAPABILITY (FLCC) - The firm load that a system could carry under coordinated operation under critical period streamflow conditions with the use of all reservoir storage (refer to page 33). More specific terms are Firm Energy Load Carrying Capability (FELCC) and Firm Peak Load Carrying Capability (FPLCC). The general term refers collectively to both.

FOREBAY - The impoundment immediately above a dam or hydroelectric plant intake structure.

FOSSIL FUELS - Coal, oil, natural gas, and other fuels originating from fossilized geologic deposits and depending on oxidation for release of energy.

GENERATION - The act or process of producing electric energy from other forms of energy; also the amount of electric energy so produced.

GIGAWATT - One million kilowatts.

HEAD

Gross Head - The difference of elevations between water surfaces of the forebay and tailrace under specified conditions. In this Appendix, gross head generally refers to the difference between normal full pool and average tailwater.

Net Head (Effective Head) - The gross head less all hydraulic losses except those chargeable to the turbine.

HEAT RATE - A measure of generating station thermal efficiency, generally expressed as Btu per (net) kilowatt-hour. It is computed by dividing the total Btu content of the fuel burned (or of heat released from a nuclear reactor) by the resulting net kilowatt-hours generated.

HYDRAULIC CAPACITY - See Capacity, Hydraulic.

INDEPENDENT RESOURCES (HYDROELECTRIC) - The hydroelectric projects of the region which are not included in the Coordinated Columbia River System (see page 135).

IMPORTS - Power imported from outside the Columbia-North Pacific Region system being considered, in this Appendix.

INTERTIE - See Transmission Interconnection.

KILOWATT (kw) - The electrical unit of power which equals 1,000 watts or 1.341 horsepower.

KILOWATT-HOUR (kwh) - The basic unit of electrical energy. It equals one kilowatt of power applied for one hour.

LOAD - The amount of power delivered to a given point.

Base Load - The minimum load in a stated period of time.

Firm Load - That part of the system load which must be met with firm power.

Peak Load - Literally, the maximum load in a stated period of time. Sometimes the term is used in a general sense to describe that portion of the load above the base load.

LOAD DIVERSITY - Literally refers to the difference between (1) the sum of the separate peak loads of two or more load areas and (2) the actual coincident peak load of the combined areas. As used in this Appendix, the term applies to the load diversity between two load areas which occurs when their annual peak loads occur in different seasons of the year.

LOAD FACTOR - The ratio of the average load over a designated period to the peak load occurring in that period. In this Appendix the term applies to annual load factor unless otherwise specified.

LOAD SHAPE (LOAD PATTERN) - The characteristic variation in the magnitude of the power load with respect to time. This can be for a daily, weekly, or annual period.

LOSSES (ELECTRIC SYSTEM) - Total electric energy loss in the electric system. It consists of transmission, transformation, and distribution losses and unaccounted-for energy losses between sources of supply and points of delivery.

MEGAWATT (mw) - One thousand kilowatts

MEGAWATT-HOUR (mwh) - One thousand kilowatt-hours.

NORMAL FULL POOL - The maximum forebay water surface elevation within the reservoir's normal operating range.

NORTHWEST POWER POOL - See page 27.

PACIFIC NORTHWEST COORDINATION AGREEMENT - See pages 31-34.

PEAK LOAD - See Load, Peak.

PEAKING - Power plant operation to meet the variable portion of the daily load. See Load, Peak.

PEAKING PLANT - A power plant which is normally operated to provide all or most of its generation during maximum load periods.

PENSTOCK - A conduit to carry water to the turbines of a hydroelectric plant (usually refers only to conduits which are under pressure).

PLANT FACTOR - Same as Capacity Factor.

PONDAGE - Reservoir power storage capacity of limited magnitude that provides only daily or weekly regulation of streamflow.

POWER - The time rate of transferring energy. Note--The term is frequently used in a broad sense, as a commodity of capacity and energy, having only general association with classic or scientific meaning.

Firm Power - Power which is considered to have assured availability to the customer to meet all or any agreed upon portion of his load requirements. It is firm energy supported by sufficient capacity to fit the load pattern. The availability of firm power is based on the same probability considerations as is firm energy.

Interruptible Power - Nonfirm power; power made available under agreements which permit curtailment or cessation of delivery by the supplier. In the Pacific Northwest, interruptible power loads are met with secondary hydro energy.

Prime Power - Prime energy shaped to fit the regional load pattern.

Secondary Power - Same as Secondary Energy.

POWER DEMAND - See Demand.

POWER SUPPLY AREA - Geographic grouping of electric power supplies as established by the Federal Power Commission in accordance with utility service areas.

PUMPED STORAGE PLANT - A hydroelectric power plant which generates electric energy for peak load use by utilizing water pumped into a storage reservoir during off-peak periods. Refer also to pages 85-87.

REGULATION (Hydroelectric System) - See pages 134-135.

REREGULATING RESERVOIR - A reservoir located downstream from a hydroelectric peaking plant having sufficient pondage to store the widely fluctuating discharges from the peaking plant and release them in a relatively uniform manner downstream.

REREGULATOR - See Reregulating Reservoir.

RESERVES

Reserve Generating Capacity - See Capacity, Reserve.

Spinning Reserve - Generating capacity connected to the bus and ready to take load. It also includes capacity available in generating units which are operating at less than their capability.

System Reserve Capacity - The difference between the available dependable capacity of the system, including net firm power purchases, and the actual or anticipated peak load for a specified period.

RULE CURVE - A seasonal guide to the use of reservoir storage.

RUN-OF-CANAL PLANT - A hydroelectric plant similar to a run-of-river plant but located on an irrigation canal or waterway instead of a stream.

RUN-OF-RIVER PLANT - A hydroelectric plant which depends chiefly on the flow of a stream as it occurs for generation, as opposed to a storage project, which has sufficient storage capacity to carry water from one season to another. Some run-of-river projects have a limited storage capacity (pondage) which permits them to regulate streamflow on a daily or weekly basis.

STORAGE

Dead Storage - The volume of water remaining in a reservoir after all of the usable storage has been withdrawn.

Gross (Total)- The total volume of water in a reservoir at normal full pool.

Seasonal Storage - Water held over from the annual high-water season to the following low-water season.

Usable Storage - The volume of storage in a reservoir which can be withdrawn for various conservation purposes (gross storage minus dead storage). As used in this Appendix the term refers to storage which can be withdrawn either jointly or exclusively for power generation.

STORAGE PROJECT - A project with a reservoir of sufficient size to carryover from the high-flow season to the low-flow season and thus to develop a firm flow substantially more than the minimum natural flow. A storage project may have its own power plant or may be used only for increasing generation at downstream plants.

TAILWATER - The water surface immediately downstream from a dam or hydroelectric powerplant.

THERMAL PLANT - A power generating plant which uses heat to produce energy. Such plants may burn fossil fuels or use nuclear energy to produce the necessary thermal energy.

TRANSMISSION GRID - An interconnected system of electric transmission lines and associated equipment for the movement or transfer of electric energy in bulk between points of supply and points of demand.

TRANSMISSION INTERCONNECTION (INTERTIE) - Transmission circuit used to tie or interconnect two load areas or two utility systems.

ULTIMATE DEVELOPMENT - The maximum contemplated generating installation at a power plant.

The following references were used in the preparation of the glossary.

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The largest share of the definitions were drawn from the Federal Power Commission glossary, but in a number of cases these definitions had to be modified or supplemented to reflect regional usage of the terms.

PARTICIPATING STATES AND AGENCIES

STATES

Idaho	Nevada	Utah	Wyoming
Montana	Oregon	Washington	

FEDERAL AGENCIES

Department of Agriculture
- Economic Research Service
- Forest Service
- Soil Conservation Service

Department of the Army
- Corps of Engineers

Department of Commerce
- Economic Development Administration
- Weather Bureau

Dept. of Health, Education, & Welfare
- Public Health Service

Dept. of Housing & Urban Development

Dept. of Transportation

Department of the Interior
- Bonneville Power Administration
- Bureau of Indian Affairs
- Bureau of Land Management
- Bureau of Mines
- Bureau of Outdoor Recreation
- Bureau of Reclamation
- Fed. Water Pollution Control Adm.
- Fish and Wildlife Service
- Geological Survey
- National Park Labor

Department of Labor

Federal Power Commission